WORKING GROUP 2 DEMAND RESPONSE PROGRAM EVALUATION – PROGRAM YEAR 2004

FINAL REPORT

Prepared for

Working Group 2 Measurement and Evaluation Committee

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1. EXECUTIVE SUMMARY

1.1 OVERVIEW OF WG2 DR EVALUATION

The goal of this report is to present a summary of findings and results from the evaluation of Working Group 2 (WG2) demand response programs, specifically, for the Critical Peak Pricing (CPP) tariff, the Demand Bidding Program (DBP), the California investor-owned utilities interruptible programs, and the California Power Authority's Demand Reserves Partnership (DRP). The scope of evaluation for the interruptible and DRP programs is significantly smaller than the scope of effort for the CPP and DBP programs. In addition, the interruptible and DRP programs part of the evaluation did not commence until summer 2004.

This evaluation was performed under the guidance of the WG2 measurement and evaluation project advisory committee consisting of representatives from the utilities, the CEC and the CPUC. The evaluation is comprised of a number of sub-studies, phases, and deliverables. The core sub-studies include a process evaluation, a market assessment, a load baseline analysis, and an impact evaluation. The process evaluation focuses on assessing the programs' procedures and processes, as well as participants' activity levels and satisfaction with the program experience. The market assessment included a quantitative survey focused on estimating DR potential, barriers, and opportunities. The load baseline analysis systematically assesses the performance of different representative-day methods. Impacts for the CPP and DBP programs for 2004 events are estimated using two of the baseline methods.

1.2 2004 DBP-CPP FINDINGS, ACCOMPLISHMENTS, AND RECOMMENDATIONS

The DBP and CPP program results for 2004 can be assessed differently depending on the contextual lens through which they are viewed. In an environment that lacked the urgency associated with the CPUC's aggressive price-responsive DR goals, the tone of findings and recommendations presented in this report would also be less urgent. If the programs were not expected to make major contributions for many years, and could be fine tuned and modified gradually over time, we would conclude that for first-year DR programs, the 2004 accomplishments were reasonable and in line with experiences with similar voluntary price-responsive programs in other parts of the country. However, our charge is to assess the 2004 program experience from the perspective of how likely they are to quickly make large contributions to the CPUC's overall price-responsive DR goals.

From this perspective, the results of this evaluation point to significant challenges associated with achieving high levels of participation in and load reduction from the voluntary 2004 DBP and CPP programs. At the same time, the process of designing, marketing and implementing the 2004 CPP and DBP programs has provided all the utilities with valuable experience and customer feedback that will help to continue to improve the DR portfolio in the future. Although it is true that adoption takes time and these programs have been actively marketed only since late 2003, the results of this research provide fairly strong evidence that the 2004 CPP and DBP programs -- in their current form and with current market conditions -- will not make as large a contribution to achieving overall DR goals as desired. Based on results of this evaluation, the market needs stronger motivation, knowledge, and capability in order for these

WG2 programs to make large contributions to the price-responsive DR goals. We do caution that the narrow range of 2004 program events and, in some cases, small potentially unrepresentative mix of participant types, limits the extent to which summer 2004 experiences and program impacts can be projected for 2005 and beyond.

Finally, although our findings and recommendations are presented in this report by program type (utility price-responsive, CPA-DRP, and utility reliability programs), there are also significant opportunities to further rationalize and optimize the overall DR portfolio across these program areas.

1.2.1 2004 DBP-CPP Key Findings

- Lack of Some Types of Program Events in 2004 Limited Learning
- Participation Levels: Low Levels of CPP Program Penetration, Significant DBP Signups for Large Customers, and Low Levels of DBP Day-Of Bidding (for *Test* Events)
- Baseline Estimation Approaches: Range in Overall Accuracy Levels Across Methods, Evidence of Systematic Biases, and High Levels of Uncertainty for Some Customers
- Significant Observable Peak Load Reductions for Active Participants
- Compensation Levels May Be Insufficient to Overcome Perceived Participation Costs
- Significant Perceptions of High Barriers to Demand Response
- Wide Range Between Self-Reports of Total DR Technical and Market Potential
- Low Numbers of DBP Bidders (especially SCE) in 2004 Day-Of Test Events
- Inability of Many DBP Participants to Confidently Reach 100 kW Bid Minimum
- Conflicting Information on Customer Need for Additional Technical Assistance

1.2.2 2004 DBP-CPP Accomplishments

- Significant Increases in Program Awareness and Familiarity
- Design and Implementation of Extensive Program Processing Systems
- Customer and Utility Experience Gained from Program Experience
- Utilization of Market and Evaluation Feedback to Modify Programs

1.2.3 DBP-CPP Recommendations

- Quantify Value of DR Benefits and Conduct DR Program Cost-Effectiveness Analyses
- Consider Tradeoffs Associated with Modifying Event Triggers to Increase Probability of Day-Ahead and Day-Of Events
- The IOUs Should Work with the CPUC on the Best Approach to Adjusting the Current Method for Reporting Program Impacts
- Consider Increasing or Modifying the Structure of the Financial Benefits of Participation, Subject to Cost-Effectiveness Considerations and Other Constraints
- Allow Customer Aggregation for DBP
- Reduce Minimum DBP Bid to 50 kW for Smaller Customers and Consider Tiered Bidding Minimum by Size
- Encourage Participants to Prepare Bidding Strategies in Advance, Request Courtesy Notification, and Provide Backup Contacts

- Consider Tradeoff Associated with Increasing Amount of Time Between Notification and Bidding
- Change PG&E Day-Of DBP Program to Replace Committed Load Approach
- Consider Expanding DBP Program Eligibility to Direct Access Customers
- Continue CPP Bill Protection and Emphasize in CPP Marketing
- Increase Attractiveness of Technical Assistance
- Continue Collaborative Efforts to Achieve Price-Responsive DR Goals

1.3 RELIABILITY PROGRAMS

Key recommendations associated with the IOU's reliability programs are listed below and discussed in Chapters 3 and 9 of this report.

- Maintain the Most Successful Features of the Existing Reliability Programs If Programs are Revised for 2005
- Assess Whether Notification Periods can be Modestly Increased
- Consider Increasing BIP Eligibility Down to 200 kW
- Consider Discontinuing the SLRP Program
- Consider Further Simplifying the Portfolio of Reliability Programs
- Manage any Migration of Customers to Newer Price-Triggered DR Programs to Maintain the Availability of Reliability Resources
- Field Test All DR Programs in Addition to Process-Only Testing

1.4 CPA-DRP FINDINGS AND RECOMMENDATIONS

Key findings and recommendations associated with the California Power Authority's Demand Reserves Program are listed below and discussed in Chapters 3 and 10 of this report.

1.4.1 CPA/DRP Findings

- The Program Had Significant Participation Through the Summer of 2004 Despite Uncertainty, Reduced Incentives, and Shifting Rules Of Participation
- Program Uncertainty Hampers Marketing Effectiveness
- Capacity Payments and DA Eligibility Attract Significant Load, and Aggregators Expect More Now that the Program Has Stabilized
- DWR Continues to Dominate Participation in the Program
- Multiple Players Add to Program Complexity, But Appear to Benefit Customers

1.4.2 CPA-DRP Recommendations

- Create Organizational Stability Well In Advance of Summer 2005
- Aggregators Should Continue to Play a Role In Delivering The Program
- Maintain Payment for Nominated Load at Current Levels
- Program Load Should Be Reported in Terms of Load Actually Nominated
- Streamline the Settlement Process

2. INTRODUCTION

2.1 DR PROCEEDING, WORKING GROUP 2, AND CPUC PRICE-RESPONSIVE DR GOALS

On June 6, 2002, the Commission adopted R.02-06-001, its Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing." In the Administrative Law Judge's Ruling Following Prehearing Conference, dated August 1, 2002, a procedural framework was established. This framework includes three working groups: WG1 - Overall Policy, WG2 - Large Customer Issues, and WG3 - Small Customer Issues. "Large Customers" is defined as customers with average monthly demands of 200 kW or greater.

In Decision 03-06-032, the Commission authorized the three investor-owned utilities' Critical Peak Pricing (CPP) tariff and Demand Bidding Program (DBP), as well as SDG&E's Hourly Pricing Option (HPO) and the California Power Authority's Demand Reserves Program (DRP). The statewide demand response measurement and evaluation (M&E) effort also began in 2003 with activities required in D.03-06-032. The decision adopted the comprehensive monitoring and evaluation plan proposed by WG2 in the December 13, 2002 report, and augmented by the March 11, 2003 report. The plan outlined M&E activities in an effort to provide information that would improve the cost-effectiveness of demand response activities going forward.

The goal underlying all of the DR programs evaluated for this report is to provide California with greater flexibility in responding to periods of high peak electricity demand. The objective in rolling out these specific programs relatively quickly with limited formal rate design research was to achieve a "quick win" that would take advantage of the new interval meters installed on customers with peak demand over 200 kW, give both customers and utilities experience in implementing statewide DR programs, and deliver significant load reductions for summer 2004.

Specific numeric goals for the price-responsive DR programs included in Decision 03-06-032 for all DR programs, not just WG2, are presented in Exhibit 2-1.

Exhibit 2-1
Overall CPUC Price-Responsive Demand Reduction Goals (2003 and 2004 figures are in MW)

	Utility		
Year	**PG&E**	**SCE**	**SDG&E**
2003	150	150	30
2004 - original	400	400	80
2004 - revised*	343	141	47
2005	3% of annual system peak demand		
2006	4% of annual system peak demand		
2007	5% of annual system peak demand		

* Revised as of 6/2/2004

2.2 OVERVIEW OF WG2 DR EVALUATION

The goal of this report is to present a summary of findings and results from evaluation of Working Group 2 (WG2) demand response programs, specifically, for the Critical Peak Pricing (CPP) tariff, the Demand Bidding Program (DBP), the California investor-owned utilities interruptible programs, and the California Power Authority's Demand Reserves Partnership (DRP). San Diego Gas & Electric's Hourly Pricing Option (HPO) pilot program was originally in scope of the evaluation but was dropped due to absence of any participation. The scope of evaluation for the interruptible and DRP programs is significantly smaller than the scope of effort for the CPP and DBP programs. In addition, the interruptible and DRP parts of the evaluation did not commence until summer 2004.

The evaluation design was developed to achieve both process and outcome objectives. The immediate focus needed to be on observing implementation to: 1) provide real-time feedback to utilities on customer response in a context that was observable by the regulatory agencies, 2) gather information on customer response to program elements to help improve existing programs and tariffs, and 3) gather information from customers, particularly non-participants, on DR in general and the offered programs in particular to inform future program design.

The evaluation is comprised of a number of sub-studies, phases, and deliverables. The core sub-studies include a process evaluation, a market assessment, a load baseline analysis, and an impact evaluation. The process evaluation focuses on assessing the programs' procedures and processes, as well as participants' activity levels and satisfaction with the program experience. The market assessment included a quantitative survey focused on estimating DR potential, barriers, and opportunities. The load baseline analysis systematically assesses the performance of different representative-day methods.

This evaluation was performed under the guidance of WG2 project advisory committee consisting of representatives from the utilities, the CEC and the CPUC. An important aspect of this work is that it was conducted on a close to real-time basis with results timed to coincide with regulatory filings and decisions. The evaluation was conducted in parallel with the program marketing and implementation throughout 2004 and reports were provided approximately every quarter. Though challenging,[1] this approach provided important feedback to policy makers and program designers and contributed to a number of proposed program changes and regulatory decisions for 2005.

The phases and key deliverables of the evaluation are summarized in Exhibit 2-2. As shown in the exhibit, three reports and three WG2 presentations have been provided during this study. These deliverables were timed to coincide with key WG2 regulatory deadlines and activities throughout 2004. Exhibit 2-3 summarizes the key data collection activities conducted for this evaluation. These activities are described in the other chapters of this report and previous project reports.

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[1] See Chapter 7 for a discussion of challenges specific to the impact evaluation portion of this project.

Exhibit 2-2
WG2 Evaluation Products, Scopes, Dates, and Associated Milestones

WG2 Evaluation Product	Scope	Date	Associated Regulatory Milestone/Process
Summary of Phase 1 Research Report	• Summarize and assess the DR marketing efforts • Preliminary assessment of awareness, participation, decision making, obstacles • Findings and recommendations to support utilities' March 31 filings • Identify key issues and questions for next phase	WG2 Presentation – March 15, 2004 Final Report - April 8, 2004	WG2 March 15 Workshop March 31, 2004 Utility Filings on Plans to Achieve DR Goals
Non-participant Market Survey Report	• Survey of representative sample of 500 non-participant commercial and industrial • Baseline information on DR awareness, familiarity, participation likelihood, load reduction potential, decision-making processes, etc. • Recommendations for increasing program participation levels	WG2 Presentation – July 13, 2004 Final Report – August 5, 2005	Kickoff of WG2 Summer Workshops
Process Evaluation Update Presentation	• CPP/DBP participation update • CPP/DBP Process evaluation issues • Introduce scope/issues for CPA-DRP evaluation • Introduce scope/issues for interruptible program evaluation	Draft presentation – August 20, 2004 Final presentation -- September 2, 2004	End of summer WG2 workshop focused on preparation of 2005 program filings October 15, 2004 utility program filings
Work-in-Progress Draft of Final Report *Final Report*	• Analysis of baseline load estimation methods • Assessment of program impacts • Post-event and end-of-summer customer survey • Process evaluation findings • CPA-DRP evaluation • Interruptible program evaluation • Findings for review of non-CA DR programs	November 24, 2004 December 16, 2004	CPUC decision on 2005 program filings (expected January 2005)

Exhibit 2-3
Summary of Data Collection

Data Collection Activity	Interviews/Data Points
Participant In-depth Interviews	28
Non-Participant In-depth Interviews	34
Initial CPP-DBP Program Manager Interviews	12
Quantitative Non-Part Survey	500
Follow-up CPP-DBP Process-Related Utility Interviews	7
Participant Interval Data	772
Non-Participant Interval Data	500
Participant On-Site Visits	17
Participant Sub-Metering	12
Secondary Research on Related Programs	60
Post-Event/End of Summer Surveys	204
CPA-DRP Interviews	23
Interruptible Program Manager Interviews	10
Interruptible Customer Interviews	15

2.3 OVERVIEW OF IN-SCOPE PROGRAMS

2.3.1 The Critical Peak Pricing (CPP) Tariff

CPP is a rate that includes increased prices during 6 or 7 hours of up to 12 "Critical Peak Pricing" days each year and reduced prices during non-critical-peak periods. Specific prices in the tariff are applied based on participating customers Otherwise Applicable Tariff (OAT). For PG&E CPP customers, savings can occur in summer only; for SCE and SDG&E customers, savings can occur year-round. PG&E and SCE customers must have an annual maximum demand greater than 200 kW; for SDG&E customers the threshold is 100 kW of annual maximum demand. The rate is not available to direct access customers. The tariffs for CPP and DBP are provided in Appendices G and H.

There are two levels of Critical Peak Pricing periods. In SCE's and PG&E's programs they are High-Price Periods (3 to 6 PM) and Moderate-Price Periods (Noon to 3PM). In SDG&E's program, they are Period 1 (3 to 6 PM) and Period 2 (11AM to 3 PM). The amounts and percentages of rate credits and charges vary among the utilities:

- PG&E's Energy rates during the High Price Periods are 5 times the Otherwise Applicable Tariff (OAT) for energy and 3 times the OAT during Moderate Price Periods. At other times in the summer, PG&E's On-peak and Part-peak energy rates for CPP participants are reduced by over 22 percent and over 3 percent respectively.

- SCE's rates are about 6.7 times the OAT during CPP High-price periods and 2.0 times the OAT during CPP Moderate-price periods. At other times in the summer, the CPP rates are about 9.3 percent less than OAT energy rates.

- SDG&E's energy rates are 10.0 times the OAT during CPP Period 1 (i.e., the high price period) and 3.79 times OAT for CPP Period 2. At other times in the summer, the CPP rates are about 9.5 percent less than OAT energy rates.

Operationally, each utility determines the day before whether there will be a Critical Peak Pricing Day the next day and notifies participants. SDG&E e-mails its participants by 4PM, SCE telephones and e-mails or pages starting at 3PM and PG&E e-mails and pages its participants by 5PM. The determination is based on the forecasted temperatures at specific locations and on other system conditions.

All of the utilities conducted a rate analysis to determine whether eligible customers would pay more or less on the CPP tariff than on their OAT, assuming their previous year's pattern of energy usage with load shifting ranging from 0 to 20 percent. Sample results of these rate analyses are summarized below:

- For both PG&E and SCE,[2] of the roughly half of eligible customers who would benefit from CPP rates without making any changes to their consumption pattern, 75 percent of them would save less than 1 percent per year, or roughly $2,000 per year.
- For SDG&E, of roughly two-thirds that would benefit on CPP with a 0 percent reduction in load, 75 percent would have savings less than 1.7 percent per year.
- For both PG&E and SCE, of the 99 percent of eligible customers who would benefit from CPP rates with a roughly 20 percent reduction during each CPP event, 75 percent would save less than 1.6 percent per year, or roughly $4,000 per year.
- For SDG&E, of roughly 75 percent that would benefit on CPP with a 10 percent reduction,[3] 75 percent of them would have savings less than 2 percent per year

2.3.2 The Demand Bidding Program (DBP)

DBP is a program that provides opportunities for customers to promise load shifting during critical periods for a "bid" incentive. SDG&E, SCE and PG&E DBP programs all allow customers with over 200 kW demand who are not direct access to participant. Bidding is an offer to curtail usage by 100 kW or more for two or more hours during program "events" and

[2] SCE results are based on GS-2 as the OAT.

[3] The rate analysis provided by SDG&E included only 0, 3, and 10 percent reduction scenarios.

receive payment equal to the amount of the estimated reduction times the predetermined DBP Price incentive.

Two kinds of "events" may occur:

- Day-Ahead events may be called by the utility when its projected hourly energy costs exceed $0.15/kWh. The DBP Price incentive during these events will equal the utility's projected hourly energy costs. These events will be for 4 or more hours between noon and 8 pm.

- Day-Of events may be called by the utility when its system reliability is threatened or when the ISO declares an emergency. Customers will receive a fixed price of $0.50/kWh for estimated reductions.

While there is no limit to the number of these Day-Ahead or Day-Of events, each utility also may declare up to two "test events." Compliant customers will receive a fixed price of $0.50/kWh for actual reductions during test events. For SCE and SDG&E, customer's usage reduction bids must be submitted via the Internet by 4:00 PM the day before a Day-Ahead event and by 1:00 PM on a Day-Of event. For PG&E, the Day-Of load reduction is based on a customer's previously specified "committed" load reduction level when they sign up for the program.

A customer's actual hourly reductions are determined by subtracting actual hourly usage from their "Expected Demand" (SDG&E's term) or "Customer Specific Energy Baseline" (SCE and PG&E's term). The baseline for each hour is determined by averaging the same hours during the three highest usage days of the last ten non-event weekdays. While there is no penalty for non-compliance, to get any payment, the customer must curtail at least 50 percent of its Bid usage and will be paid for usage reductions up to 150 percent of its Bid usage.

One of the few differences among the programs is in the form of notification customers receive: SDG&E will e-mail, SCE will telephone, PG&E will e-mail and page using its proprietary Inter-Act System.

Examples of potential savings for DBP customers were estimated below based on amount of demand reduction and the type of bid, assuming participation in four demand reduction incidents per year and four hours per demand reduction incident. Day Before savings were calculated at 15 cents/kWh, Day Of calculated at 50 cents/kWh. As shown in Exhibit 2-4, the resulting savings ranged from $240 for 100 kW for a Day-Before Bid to $4,000 for 500 kW for a Day-Of Bid.

Exhibit 2-4
Example Customer Savings for DBP Participation

# of Events	Savings in kW	Day Before Bid (@15 cents per kWh reduced)	Day Of Bid (@50 cents per kWh reduced)
4	100	$240	$800
	200	$480	$1,600
	500	$1,200	$4,000
	1,000	$2,400	$8,000
12	100	$720	$2,400
	200	$1,440	$4,800
	500	$3,600	$12,000
	1,000	$7,200	$24,000

2.3.3 CA Power Authority Demand Reserves Partnership

The California Power Authority's Demand Reserves Partnership (DRP) Program is available to direct access customers as well as large bundled service customers. Like the Demand Bidding Program, customers provide demand reductions when contacted and receive payments for reductions; in addition, however, customers also receive a reservation payment. This program is offered by the California Power Authority, but is marketed by the utilities and energy service providers. This program is described in more detail in Chapter 10 of this report.

2.3.4 CA IOU Interruptible Programs

These programs are addressed in Chapter 9 of this report. Programs include: Traditional non-firm rates ("Non-firm"), including PG&E's Schedule 19 and Schedule 20 non-firm service schedules, SCE's I-6 non-firm schedule, and SDG&E's AL TOU CP (including Schedule EECC) service; Base Interruptible Program (BIP); Optional Binding Mandatory Curtailment program (OBMC); Scheduled Load Reduction Program (SLRP); and SDG&E's Rolling Blackout Reduction Program (RBRP).

2.3.5 Transitional Incentives

The following two incentives were offered to encourage customers to participate in the 2004 DBP and CPP programs:

- The Bill Protection Incentive was intended to assure participants they would not pay more under the CPP tariff than they would have under their otherwise applicable tariff (OAT) for the first 14 months they participate in the CPP program. Originally, to receive the incentive, the customer must have reduced on-peak usage by an average of 3 percent for each CPP event during those 14 months. Subsequently, based on utilities' request to modify the incentive in their March 31 filings, the 3 percent requirement was eliminated.

- The Technical Assistance incentive provides CPP or DBP participants with a cash incentive of up to $50 per kW of curtailable on-peak load reduction to cover the cost of load reduction feasibility studies conducted by CEC-approved professional engineers. Customers receive half the incentive upon certification by the engineer; to receive the other half, customers must provide actual load reductions averaging at least 50 percent of the certified amount during CPP or DBP events.

2.4 GUIDE TO THIS REPORT

The report includes the following chapters and appendices:

- Chapter 1 – Executive Summary
- Chapter 2 – Introduction
- Chapter 3 – Summary of Key Findings and Recommendations
- Chapter 4 – 2004 CPP-DBP Program Participation Tracking and Analysis
- Chapter 5 – Participant Post-Event and Final Evaluation Survey Results
- Chapter 6 – Baseline Assessment
- Chapter 7 – CPP and DBP Impact Evaluation
- Chapter 8 – CPP and DBP Process Evaluation
- Chapter 9 – Interruptible Programs Evaluation
- Chapter 10 – CPA-DRP Program Evaluation
- Chapter 11 – Review of Non-California Demand Response Programs
- Appendix A – CPP Program Materials (Tariffs, Brochures)

- Appendix B – DBP Materials (Tariffs, Brochures)
- Appendix C – Statewide CPP and DBP Materials
- Appendix D – Post-Event and Final Evaluation Survey Instruments
- Appendix E – Post-Event and Final Evaluation Survey Tables
- Appendix F – Baseline Analysis Tables
- Appendix G – Impact Analysis Tables
- Appendix H – Program Features Matrix / Interruptible Event History
- Appendix I - U.S. DR Program Comparison Matrix
- Appendix J – DR Sub-Metering Process and Results
- Appendix K – Submetering Recruitment and Data Collection Documents

3. SUMMARY OF KEY FINDINGS AND RECOMMENDATIONS

This chapter summarizes our findings from the overall WG2 evaluation activities. Findings and recommendations are presented first for the DBP and CPP programs. We then present findings and recommendations associated with the evaluation of utility interruptible programs, followed by those associated with the CPA's DRP program. A section on accomplishments that have been made through the implementation of these programs in 2004 is also included. We also present lessons learned from our review of related non-California programs. Detailed results and additional findings are presented in each of the remaining chapters of this report, as well as our previously published reports for this study (see Exhibit 2-1 in Chapter 2).

Although our findings and recommendations are presented in this section by program type, there are also opportunities to further rationalize and optimize the overall DR portfolio. Having a wide range of programs has the advantage of providing different products suited to different customer needs; however, from the customer's vantage point, the range of new and legacy DR programs can appear bewildering. From a resource point of view, there is a significant gap between the size of the traditional reliability programs, which are not counted toward the CPUC's price-responsive goals, and the current relatively modest size of the 2004 voluntary CPP and DBP programs. Factoring the Demand Reserves Program into this mix is challenging given the changes in program requirements and administration that occurred in 2004; nonetheless, it has recently re-emerged as a potentially important contributor to the price-responsive goals. We recommend that the CPUC, utilities, and other stakeholders continue working together toward a comprehensive approach to demand response that will increase the likelihood of achieving the CPUC's price-responsive goals, while also maintaining a significant DR reliability resource.

3.1 2004 DBP-CPP FINDINGS, ACCOMPLISHMENTS, AND RECOMMENDATIONS

In this section, we summarize the key issues associated with our evaluation findings, program accomplishments, and our overall recommendations.

As mentioned in Chapter 2 of this report, the objective in rolling out the new 2004 DBP and CPP programs relatively rapidly, with limited formal rate design research, was to achieve a "quick win" that: a) would take advantage of the new interval meters installed on customers with peak demand over 200 kW (100kW for SDG&E), b) give both customers and utilities experience in implementing statewide DR programs, c) deliver significant load reductions for summer 2004, and d) make a significant contribution to achieving the CPUC's overall price-responsive demand response goals (which ramp up to 5 percent of system peak by 2007).

The DBP and CPP program results for 2004 can be assessed differently depending on the contextual lens through which they are viewed. In an environment that lacked the urgency associated with the CPUC's aggressive price-responsive DR goals, the tone of findings and recommendations presented in this section would also be less urgent. If the programs were not expected to make major contributions for many years, and could be fine tuned and modified gradually over time, we would conclude that for first-year DR programs, the 2004 accomplishments were reasonable and in line with experiences with similar voluntary price-responsive programs in other parts of the country. However, our charge is to assess the 2004 program experience from the perspective of how likely they are to quickly make large contributions to the CPUC's overall price-responsive DR goals.

From this perspective, the results of this evaluation point to significant challenges associated with achieving high levels of participation in, and associated load reduction from, the 2004 DBP and CPP programs. The primary areas of concern regard levels of participation for CPP and potential levels of bidding activity for DBP. The issue of DBP bidding levels was particularly difficult to assess given that only day-of events were called in 2004 and most of those were test events. Although it is true that adoption takes time and these programs have been actively marketed only since late 2003, the results of this research provide fairly strong evidence that the WG2 DR programs -- in their current form and with current market conditions -- will not make as large a contribution to achieving overall DR goals as desired. Based on results of this evaluation, the market needs stronger motivation, knowledge, and capability for these WG2 programs to make significant contribution to the price-responsive DR goals.

We caution, however, that the narrow range of 2004 program events and, in some cases, small potentially unrepresentative mix of participant types, limits the extent to which summer 2004 experiences can be projected for 2005 and beyond. Despite these limitations, a number of modifications and considerations are suggested below. The utilities have also proposed significant modifications in their October 15, 2004 filings. In addition, reflecting the urgency with which the CPUC believes price-responsive DR needs to be increased, the CPUC has just issued an Assigned Commission Ruling directing the utilities to file new rate design proposals that would include default Critical Peak Pricing rates for large customers.[1] Because this ACR was issued as this evaluation was being finalized, our recommendations remain within the original evaluation context of voluntary CPP and DBP programs.

The fact that this is a new set of programs in there initial year of implementation must be kept in mind when reviewing the results.[2] The learning curve may be steep, but considerable progress has been made in the areas of marketing, implementation and factors that influence customer acceptance and satisfaction.

3.1.1 2004 DBP-CPP Findings

In this section, we summarize our key findings that affect both the DBP and CPP programs. These include:

- Lack of Some Types of Program Events in 2004 Limited Learning
- Participation Levels: Low Levels of CPP Program Penetration, Significant DBP Signups for Large Customers, and Low Levels of DBP Day-Of Bidding (for <u>*Test*</u> Events)

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[1] *Assigned Commissioner and Administrative Law Judge's Ruling Directing The Filing Of Rate Design Proposals For Large Customers*, Rulemaking 02-06-001, December 8, 2004, http://www.cpuc.ca.gov/PUBLISHED/RULINGS/42078.htm

[2] Note, however, that the DBP program did have pre-cursers prior to 2004.

- Baseline Load Estimation Approaches: Range in Overall Accuracy Levels Across Methods, Evidence of Systematic Biases, and High Levels of Uncertainty for Some Customers

- Load Reduction Impacts: Significant Observable Peak Load Reductions for Active Participants

- Compensation Levels May Be Insufficient to Overcome Perceived Costs of DR Participation for Many Customers

- Significant Perceptions of High Barriers to Demand Response

- Wide Range Between Self-Reports of Total DR Technical and Market Potential

- Low Numbers of DBP Bidders (especially SCE) in 2004 Day-Of Test Events

- Inability of Many DBP Participants to Confidently Reach 100 kW Bid Minimum

- Adequacy of Notification and DBP Bidding Timing

- Limited Experience with Notification and Use of Websites

- Inability of Customers to "Bid" and Use of Committed Load in PG&E Day-Of DBP

- Conflicting Information on Customer Need for Additional Technical Assistance

Lack of Some Types of Program Events in 2004 Limited Learning

Only a small number of DBP events were called in summer 2004 and these were all Day-Of events. The price triggers for Day Ahead DBP events were never hit. For the Day-Of events, PG&E called one event, SCE two events, and SDG&E three events, all of the PG&E and SCE events were "test" events, while one of the SDG&E events was a test event. Customers and program implementers thus did not have the opportunity to gain experience with the Day-Ahead aspect of the program. In addition, conditions under some of the DBP test events were relatively cool. The small number of 2004 DBP events, predominance of test events, modest temperatures, and the fact that all events were Day-Of events severely limited the impact evaluation and confidence with which program impacts can be estimated.

The number of CPP events called in 2004 ranged from five and six for PG&E and SDG&E, respectively, to 12 for SCE. However, three of the PG&E events were called on consecutive days during which time temperatures significantly decreased, which limited the usefulness of the last two events in the impact analysis (see Chapter 7). One issue relating to the lack of frequency of CPP events is the appropriateness of the temperature triggers that determine how often the program is called. There are indications that the triggers for some regions were set relatively high, resulting in the program being rarely called. In SDG&E's territory, for example, the CPP program is triggered when the forecast temperature for a certain location reaches 91 degrees; however the forecast temperature for that location has not been as high as 91 degrees in the past five years.

Participation Levels: Low Levels of CPP Program Penetration, Significant DBP Signups for Large Customers, and Low Levels of DBP Day-Of Bidding (for *Test* Events)

Program penetration levels for the 2004 CPP and DBP are summarized in Exhibit 3-1 below (detailed penetration levels by utility, size, and business type are provided in Chapter 4). Overall, roughly 5 percent of accounts signed up for either CPP or DBP. In terms of eligible non-coincident load, combined program penetration was 8 percent. Most of these, however, were signups in SCE's DBP program, a program segment for which we are uncertain about the level of future bidding activity (see related finding below). Program penetration was significantly higher for medium and large customers as compared to small customers.

Exhibit 3-1
***WG2 DR Program Penetration Across All Utilities*[3]**

3 IOUs	Participant Penetration	Participant MW Penetration*	Participant GWh Penetration*	CPP Penetration	DBP Penetration
Size					
Very Small (100-200 kW) - SDG&E Only	0.5%	0.6%	0.3%	0.4%	0.3%
Small (200-500 kW)	3.2%	3.0%	4.1%	0.6%	2.7%
Medium (500-1000 kW)	7.4%	7.6%	8.0%	2.1%	5.6%
Large (1000-2000 kW)	10.9%	11.0%	11.8%	3.1%	8.6%
Extra Large (2000+ kW)	11.1%	10.9%	20.4%	1.6%	10.1%
Business Type					
Commercial and TCU					
Office	1.8%	2.6%	3.2%	0.3%	1.6%
Retail/Grocery	7.6%	6.8%	9.0%	0.1%	7.5%
Institutional	2.6%	6.9%	8.7%	1.0%	1.7%
Other Commercial	4.5%	7.5%	8.1%	1.0%	3.7%
Transportation/Communication/Utility	6.2%	5.2%	7.5%	1.8%	4.5%
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	8.0%	9.1%	12.8%	1.0%	7.1%
Mining, Metals, Stone, Glass, Concrete	8.2%	23.7%	31.9%	0.7%	7.8%
Electronic, Machinery, Fabricated Metals	6.2%	14.8%	20.3%	2.0%	4.5%
Other Industrial and Agriculture	4.1%	8.5%	10.8%	1.3%	3.1%
Unclassified					
Unknown	10.5%	5.2%	13.4%	4.1%	6.7%
Total Accounts	4.7%	8.0%	11.2%	1.1%	3.8%

*Diversified customer peak demand

CPP Penetration. Only 1 percent of eligible accounts participated in CPP for summer 2004; however, participation was higher among larger customers. Participation varied greatly by utility, 2 percent of eligible PG&E accounts signed up (146 accounts), 1 percent of SDG&E (52 accounts), and only 0.1 percent (8 accounts) for SCE. Although there are some differences in tariff design across the utilities, the differences in potential customer savings for PG&E and SCE are similar and do not explain the difference in program penetration levels.

As shown in Chapter 2, by design, roughly 50 percent of eligible customers would benefit on the CPP without making any change in their load shapes. For most of these customers,

[3] DBP Penetration in the Retail/Grocery business type is significantly skewed by a series of SCE program signups. See Exhibit 4-15 and associated discussion in Chapter 4 for further explanation.

however, the level of benefit is very small, on the order of 1 percent of their annual bill. This small benefit plus any uncertainty customers have about the stability of the CPP itself as well as future changes in their load shapes due to weather or other factors appears to have limited participation significantly in 2004. It is unclear at this time whether the changes to the CPP Bill Protection Plan early in the summer could still lead to significant increases in participation. These changes came after the utilities had completed their intensive one-on-one program marketing to their largest customers in late 2003 and early 2004.

DBP Penetration. Overall, roughly 4 percent of eligible DBP accounts signed up to participate for summer 2004. Participation increases by size from roughly 3 percent for small customers to 10 percent for the largest end users. Participation by utility ranges from 1 to 2 percent for SDG&E and PG&E, respectively, to 7 percent for SCE. The overall average penetration appears relatively high because of the large number of SCE DBP participants.

Only 43 of 607 SCE DBP participants bid load for at least one of SCE's two DBP test events. This represents only 7 percent of those signed up for the program. Even though these were only test events, this is a very small fraction of signups and is cause for concern. For SDG&E, 13 of 47 participants roughly (27 percent) bid in at least one of the three Day-Of events, only one of which was a test event. For PG&E there were no "bidders" per se since PG&E's 2004 DBP did not allow for actual bidding on day-of events, however, based on interviews with participants, 33 percent said they took load reduction in response to the event notification.

Because only test events were called by SCE in 2004, the level of bidding observed should not be considered representative of what would occur for real events, particularly if customers believe system reliability is at risk. Program managers and a portion of interviewed customers indicate that many customers are participating strictly for reliability or civic duty reasons, not because of the potential financial payments, which most customers consider modest at best. Thus, it is likely that many more participants would take action in a real event. How many more, is very unclear at this time. Results from our interviews with participants indicate that a third of non-bidders in 2004 DBP events said they were somewhat unlikely or very unlikely to bid in a DBP event in the future.[4]

There is some evidence on this issue from the other two utilities. For example, two of SDG&E's three Day-Of DBP events were real events, not tests. There was, however, no difference in the level of bidding activity between the test and actual events, which was only roughly 20 percent for each event. For PG&E, a single Day-Of test event was called; however, further complicating matters, the event was communicated to participants as "mandatory" and the PG&E DBP program was not set up to allow actual bidding for Day-Of events in 2004 (instead, customers were paid based on a "committed" load amount they were required to specify when they signed up for the program).[5] In any case, analysis of the PG&E Day-Of DBP event indicates that a third of participants reduced load by 100 kW or more.

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[4] Participants with very low likelihood or bidding on future DBP events may also have been less likely to participate in our evaluation survey, thus, this figure may understate the share of participants will low bidding likelihood.

[5] PG&E plans to change this approach in 2005 to allow Day-Of bidding consistent with the other two utilities.

Another reason for the low percentage of bidders in these predominantly Day-Of events may be that many participants may be able to take action on a Day-Ahead but not Day-Of basis. Our survey results show that of those who did not bid, 39 percent said it was because they could not reduce load on that particular day. Other reasons included: Never planning to bid for any event (10 percent), People responsible for bidding were not there (10 percent), Did not get notification in time (9 percent), System issue/no password (9 percent), Could not respond that fast (4 percent), Not available to bid that hour (4 percent), Event was cancelled (4 percent), Operation was already shut down (3 percent), Don't need to take action to save money (2 percent), and Unhappy with first bid (2 percent).

Finally, low levels of bidding in 2004 may reflect lack of experience, knowledge, and capability for some customers. There may be significant upside potential in the DBP participant population that can be captured through increased customer assistance with developing DR plans and capability.[6]

Baseline Load Estimation Approaches: Range in Overall Accuracy Levels Across Methods, Evidence of Systematic Biases, and High Levels of Uncertainty for Some Customers

Hourly load baselines are an important part of this evaluation and voluntary DR bidding-type programs. Baselines are used to estimate individual customer loads that would have occurred in the absence of participation in program events. As discussed in Chapter 6, there are a variety of different methods that can be used to develop such baselines. Two principal applications of hourly load baseline methods are to estimate total program savings for evaluation purposes, and to estimate individual load impacts for program settlement (e.g., payment of DBP incentives for load reductions achieved). Different baseline methods have different strengths and weaknesses when applied to different applications.[7] This evaluation analyzed several different types of baseline methods,[8] including the method used for customer settlement in the DBP program.

The current baseline methodology that is being used for settlement at each of the three utilities for the CPP and DBP programs is referred to as the 3-Day Baseline. This baseline is calculated by first selecting a series of 10 days that represent the most recent 10 similar days that occurred prior to the event day. The first alternative baseline methodology evaluated was for the 10-Day Baseline. This baseline is similar to the 3-Day baseline in that it also selects a series of the last 10 similar days. However, as opposed to selecting the three highest days from the last 10 days, this approach calculates the baseline for each hour by averaging the hourly load over all of the last

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[6] For example, one of the SCE participants in our Sub-Metering sample, a college campus that did not bid in 2004 (see Chapter 12), has been working all summer and through the end of 2004 on a sophisticated monitoring and control system that will enable bidding for 2005.

[7] For example, as discussed in Chapter 6, more complex methods may be useful for evaluations but inappropriate for use for program settlement. Program settlement methods tend to trade off simplicity of application, explanation, and agreement with customer participants, against the potential greater overall accuracy but complexity of statistical methods. The baseline methods analyzed for this study are described in Chapter 6.

[8] This evaluation focused on a subset of a larger group of baseline methods analyzed in *Protocol Development for Demand Response Calculation – Findings and Recommendations*, prepared by KEMA-XENERGY Inc. for the California Energy Commission, February, 2004. www.energy.ca.gov/demandresponse

10 similar days. The second alternative baseline methodology evaluated was for a 10-Day Adjusted Baseline. The 10-Day adjusted baseline is calculated by applying a scalar adjustment to the 10-Day baseline (as described above) based on a series of calibration hours.[9] This baseline is similar to the baseline currently being used for settlement in the California Power Authority's Demand Reserves Partnership (CPA-DRP) program and the Optional Binding Mandatory Curtailment (OBMC) program.

The accuracy of the baseline load estimation methods analyzed in this study was found to vary across methods, day types (e.g., high temperature versus low temperature), customer size, and type of business (industrial versus commercial). The 3-Day method used for program settlement was found to systematically over-predict baseline loads on average. The method found to perform best on average, was the 10-Day Adjusted baseline. The method did an excellent job of predicting baseline loads on average and was only very slightly biased. From an evaluation point of view, the errors and biases in the baseline methods can lead to over- or under-estimates of load reductions when load reductions are of modest size as compared to the size of the baseline errors.

In addition, in the program impact analysis (Chapter 7), we found that small numbers of large customers with highly variable loads can cause very large differences in the absolute magnitude of estimated program savings across baseline methods. For some of these customers and particular event day circumstances, none of the baseline methods could be relied upon to produce unbiased results. As a result, individual visual inspections were made of the two weeks leading up to and including the event day, along with the baseline method estimates, in order to estimate impacts. Although this approach is viable for evaluation purposes, program settlement requires easy-to-understand, pre-determined, transparent methods. Some individual customer loads will invariably be miss-estimated using these approaches, but many errors will cancel when averaged across all the customers in a program. Nonetheless, large individual customer errors can bias results when active program populations are small, as they were in summer 2004.

Load Reduction Impacts: Significant Observable Peak Load Reductions for Active Participants

Load reduction impacts were estimated for both the CPP and DBP programs for each utility and event. Load reductions were estimated using two of the baseline methods analyzed in Chapter 6 – the 3-Day Baseline method used for program settlement and the 10-Day Adjusted Baseline, which had the best overall performance. Our evaluation results are based on the 10-Day Adjusted Baseline.

CPP 2004 Impacts. The overall estimated load reduction is roughly 8 MW for the 2004 CPP across utilities. PG&E accounts for 60 percent of the estimated impact, SDG&E 30 percent, and SCE 10 percent. On a percentage basis, the average impacts range widely across the three utilities. For PG&E and SDG&E, which had the vast majority of CPP participants, average percent savings ranged from a few percent up to 20 percent depending on the utility and event.

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[9] The scalar adjustment factor was calculated by computing the ratio of the average load over three calibration hours to the average load for the same three hours from the last 10 similar days. Multiplying each hour of the 10-Day baseline by the scalar adjustment factor gives us the 10-Day Adjusted baseline, which is essentially the 10-Day baseline scaled to the customer's same-day operating level for the calibration hours.

For planning and CPUC reporting purposes, the IOUs are currently using an impact estimate for CPP that is 15 percent of load. For PG&E, the 15 percent figure is on the higher end of what might be expected, for the particular customers in the 2004 participant cohort, based on the results presented in Chapter 7. The mean impact estimated using the 10-Day Adjusted Baseline is 5 percent of load based on the first two event days (event days for which we are more confident in the estimates). Even if all four event days are used (of which the latter two are believed to be overstated), the mean impact is 9 percent.[10] For SDG&E, the average impact using the 10-Day Adjusted Baseline across six CPP events is 15 percent.[11] For SCE, however, it is difficult to assess if the 15 percent value currently used by the IOUs is appropriate due to the small number of participants in the program. Although the impact is estimated to be 55 percent of load, this value is driven primarily by a single customer. The median impact is 9 percent and the inter-quartile range is zero to 73 percent. Therefore, the value of 15 percent is likely a better value to be using going forward for planning purposes than 55 percent.

Overall for CPP, given the small number of event days, the influence of some large customers over some IOU-specific results, and the weather patterns on and surrounding some of the event days, we cannot reject the a priori estimate of 15 percent, particularly since the mix of customer types could change significantly as new customers participate.

DBP 2004 Impacts. As with the CPP impacts, it is difficult to identify a reliable DBP impact estimate that can be used prospectively to forecast expected savings given the limitations associated with the 2004 results. This is primarily because, as discussed previously, there were very few DBP events, most of these were test events, and very few of the applicable customers placed bids for these events. Within the constraints of these caveats, we estimated the overall load reduction associated with these primarily test events is roughly 27 MW for the 2004 DBP across utilities. PG&E accounts for roughly 60 percent of the impact, SCE 36 percent, and SDG&E 4 percent.

As with CPP, on a percentage basis, the average DBP impacts range widely across the three utilities. For DBP events, the impact of the single PG&E event was 17 percent across all participants (since there was no bidding in PG&E's Day-Of test). For SCE and SDG&E, impacts across only those who bid ranged from 12 to 50 percent for SCE, and 19 to 28 percent for SDG&E.

For DBP, the IOUs are also currently using an estimate of 15 percent of load for planning and reporting purposes. This value does appear to be reasonable *among bidders*, based on the empirical results presented in Chapter 7, considering the small number of event days, the influence of some large customers over some IOU-specific results, and the weather patterns on and surrounding some of the event days. However, as discussed in the recommendations in Section 3.1.3, because there were so few bidders for the SCE and SDG&E events (less than 5

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[10] The median impact for the first two PG&E CPP event days is 1 percent of load, with an inter-quartile range of –5 percent to 9 percent, which does not contain 15 percent (however, including all four event days, the inter-quartile range is -1 percent to 18 percent).

[11] The distribution of impacts for all SDG&E CPP participants across the 6 events has an inter-quartile range (25th percentile to the 75th percentile) of –1 percent to 22 percent, which contains 15 percent.

percent for SCE and roughly 20 percent for SDG&E), it is difficult to draw any definitive conclusion on the level of impact that can be expected from the DBP program in the future.

Levels of Compensation May Be Insufficient to Overcome Perceived Costs of DR Participation for Many Customers

As shown in Chapter 2, the monetary incentive to customers to reduce load in the CPP and DBP programs are relatively small, particularly as compared to customers' annual electricity bills and other costs of doing business. For example, a 2 MW facility that reduces load by 500 kW for four hours and four Day-Of events would save $4,000 in the DBP program. Assuming this was a 25 percent load reduction and the customer has 5,000 peak-load equivalent hours of operation, the associated savings as a percent of their annual bill would be on the order of 0.4 percent. For 12 Day-Of events, savings would be just over 1 percent. Similarly, as discussed above, CPP savings are roughly 1 to 2 percent for most customers that benefit on the voluntary rate (without any peak load reductions). Our non-participant market survey analysis[12] and other recent related research[13] showed very low levels of customer willingness to make load reductions in exchange for bill savings of a percent or two a year.

There is evidence that the current levels and form of compensation may not be motivating a larger share of the eligible market to participate in the CPP and DBP programs because customers believe that their costs of participating in the programs and taking associated DR actions may exceed the corresponding financial incentives. There is consistent evidence that end users face both fixed and variable costs associated with DR actions. Fixed costs are associated with development of a DR action plan, which may require a variety of engineering and financial analyses, as well as implementation of fixed elements of the plan (for example, programming EMS or other control systems, purchase of new equipment, modification of existing equipment, etc.).[14] Variable costs include costs associated with carrying out the DR actions, which could include costs associated with lost or deferred production, decreased worker productivity, as well as the costs of physically carrying out the reductions (in cases where they are not automated).

It is important to recognize that perceived costs are as relevant to customer decision-making as are actual costs. There is certainly an extremely wide range of actual costs across customers attributable to taking DR actions; however, there also may be a wide range of perceived costs, as well as cases where perceived costs greatly exceed actual. Some of the actual and perceived costs associated with DR actions can likely be reduced through provision of technical information and services, which is discussed in related findings and recommendations below.

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[12] The non-participant market survey results were published in an earlier report volume, see Chapter 2 for reference. Readers interested in understanding barriers to demand response, likelihood of participation in voluntary programs, and DR potential, are strongly encouraged to review the market survey report.

[13] *Critical Peak Pricing (CPP) Rate Design Preferences Survey of Mid-Size / Large C&I Customers*, prepared by Momentum Market Intelligence for Southern California Edison Company, May 2004.

[14] For more information on these types of costs and associated activities, see the California Energy Commission's Enhanced Automation *Technical Options* and *Business Case Guidebooks* for end users at:

http://www.consumerenergycenter.com/enhancedautomation/

Significant Perceptions of High Barriers to Demand Response

Based on the results of our non-participant survey, customers indicated that there are numerous barriers that limit their ability and willingness to participate in DR programs. In rating potential barriers to participation and implementation, the number one concern for the market as a whole was "Effects on Products or Productivity". The next largest concerns were "Amount of Potential Bill Savings", "Level of On-peak Prices or Non-performance Penalties", and "Inability to Reduce Peak Loads". The least significant concern reported was "Inadequate Program Information". The rating of barrier importance varied greatly by market segment, for example, Institutional and Office customers ranked concerns over occupant comfort very high, while industrial customers considered this a relatively insignificant issue. Barriers that were more of a concern for those who said they were *very likely* to participate in DBP or CPP included "Amount of Potential Bill Savings", "Complexity of Program Rules", "Uncertainty over Future Program Changes", and "Level of On-Peak Prices or Non-Performance Penalties" all of which indicate concerns with program design, economics and change associated with a developing market rather than actual load reduction.

Wide Range Between Self-Reports of Total Technical and Market Potential for DR

In our non-participant survey, several questions were asked of customers to develop inputs for estimation of the potential load reduction associated with the large nonresidential market for demand response in the service territories of the three IOUs. It is important to note that the resulting estimates of potential are based on customer self-reports and have not been independently confirmed with on-site engineering analyses. The average *technical* potential reported from the market was 16 percent, however, the average varied widely by market segment.[15] Based on rough initial estimates of the range of coincident peak demand for this population, the total technical MW reduction potential is likely in the range of 1,600 MW.[16] Note, however, that technical potential assumes the customer received sufficient financial motivation (see previous footnote), regardless of whether such levels of compensation are cost-effective to the utility system. In addition, this estimate of potential contains partial overlap with the IOUs' current interruptible participants.[17] The magnitude of DR potential drops when customers are asked to report how much they would require in bill savings to deliver DR load

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[15] To develop very rough estimates of the DR capability that currently exists customers were asked a hypothetical question asking what percent of their normal summer afternoon peak demand their company would be willing and able to reduce for a few hours on four weekdays in the summer, provided they were notified the day before, and were given *sufficient financial motivation*. The estimates were calculated using the self-reported reduction ranges and can be considered the upper bound of the near-term technical potential since there may be a tendency with self-reports to over-estimate true ability. At the same time, because DR knowledge and automation capabilities are still relatively limited and nascent, one would expect that the longer-term DR technical potential would be higher if improvements in knowledge and controls automation increase.

[16] Using interval data obtained for the IOUs for this study for a representative sample of 500 customers eligible for the 2004 CPP and DBP programs, we estimate the total coincident peak demand for the eligible population is roughly 10,000 MW.

[17] Thirty-six percent of the technical potential was attributable to the 13 percent of the surveyed population that was participating in another DR program, primarily interruptible programs.

reductions.[18] At bill savings similar to those associated with the current DBP and CPP programs (that is, a few percent of annual bills), the potential decreases by an order of magnitude, to a level on the order of 100 MW. Note that significant DR potential was reported across all eligible size groups, including the smallest customers.

Despite the large drop-off between estimated technical and current market potential, somewhat surprisingly, a large portion of the market reported being willing to take specific DR actions on a limited number of hot summer afternoons, regardless of compensation. These actions included allowing the temperature to rise in their occupied space by 1 to 5 degrees, shutting off a portion of the air conditioning system, reducing the overhead lighting, and reducing or shutting off their production process.[19]

Inability of Many DBP Participants to Confidently Reach 100 kW Bid Minimum

Another potential limitation on bidding in the summer 2004 events as well as participation levels may be the 100 kW bid minimum. SCE signed up a large number of participants in the 200 to 500 kW size range - 286 of their 607 DBP accounts (47 percent). As discussed in the March 2004 report, it appears that some account representatives may have encouraged customers to sign up for the DBP program when they were unlikely to be able to curtail the minimum 100 kW required, or for all practical purposes are unwilling to do so. There was some confusion among SCE account reps and smaller customers in particular regarding the 100 kW minimum, with some apparently interpreting the 100 kW as the minimum bid for the program, so that 50 percent of that bid – or 50 kW – would be sufficient for a customer to be compensated. Any ambiguity in the wording of the program materials was subsequently corrected, but not before a large number of relatively small SCE customers had signed up for the DBP program. Most of these customers subsequently did not bid on any of the DBP test events implemented by Edison and are still listed as program participants (as noted in Chapter 4, this tends to distort analysis of participant versus non-participant characteristics).

Adequacy of Notification and DBP Bidding Timing

The utilities offer a combination of telephone, email, and pager notification to primary and secondary contacts. Despite these multiple notification options, it can still be difficult to reach contacts with the authority and knowledge to place bids within the one hour time frame for a Day-Of event.

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[18] To benchmark the technical potential results, which were based on the hypothetical assumption of *sufficient* financial motivation, two questions were asked that sought more specific information on how much financial motivation customers would need to achieve specific levels of demand reduction. Customers were asked what percentage of their annual electricity bill they would need to save as an incentive to reduce their demand by 5 percent and 15 percent for a few hours in the late afternoon on approximately four non-sequential weekdays in the summer. The percentage of customers that said they could reduce their peak load by these amounts for compensation levels lower than 5 percent of their annual bills were used as the basis for the current market potential estimates, since all other customers required higher levels of bill savings in exchange for the load reductions.

[19] Surprisingly, over 92 percent of the market responded they were willing to consider one of these four DR actions and nearly half (48 percent) reported they were willing to consider three of the four demand reduction actions (allowing AC to be shut off, allowing the temperature to rise in the occupied space or reducing the overhead lighting). Customers were less likely to consider the fourth action, reducing or shutting off their production process, with only 31 percent of the applicable market saying they would consider this action.

Overall satisfaction with the amount of notification process was relatively high, 81 percent of customers said they were somewhat or very satisfied with the amount of notification they received, with CPP participants much more likely to be very satisfied than DBP participants. The lower level of satisfaction among DBP participants may be related to their inability to curtail in the time required.

While DBP participants appear to need less time to actually curtail usage than they do to submit bids (64 percent can curtail within 2 hours, but only 38 percent can bid in that time), a substantial portion cannot meet the requirements of the program, which require customers to curtail on same day events within one hour of having their bid accepted. While the tariffs and program materials explicitly set out the time frames for notification and curtailment, a number of customers reported concerns both about the time allowed to respond to DBP bid requests and about the notification given for curtailments. Furthermore, the low percentage of program participants submitting bids for test events this summer may be explained in part by the survey responses regarding the amount of time required both to submit bids and curtail load. In explaining why the one-hour frame made them less likely to place a bid, customers typically said either that they cannot react that quickly (45 percent) or that the person in charge is hard to reach (38 percent).

Limited Experience with Notification and Use of Websites

DBP participants have trouble with receiving and responding to notifications to bid; failure to reach the individual responsible for curtailment by the standard notification process caused some participants to miss opportunities to bid. Program managers should encourage participants to a) sign up for courtesy notifications that will reach key individuals when they are away from their desk, such as alphanumeric pagers or cell phones, or b) identify back-up individuals who have authority to place a bid and launch a curtailment.

Inability of Customers to "Bid" and Use of Committed Load in PG&E Day-Of DBP

There has also been some confusion surrounding the PG&E day-of test events. While these are nominally tests of the DBP, PG&E's DBP tariff, as originally written, did not allow PG&E to accept bids for these test events. Instead, customers are issued a notification that says the test event is mandatory and participants must reduce by the amount of their committed load (even though customers face no penalties for failing to reduce). Some customers have confused the notification with that for other interruptible rates[20] of DR programs; others tried to submit bids or contacted PG&E. The level of curtailment for PG&E DBP customers also varied widely, with significant over- and under-bidding. Only 22 of the 31 participants who reduced their usage by more than 100 kW for the first 2004 PG&E DBP test event received any payment, and several provided reductions in excess of 150 percent of their committed load for which they were not compensated (based on the program's 3-Day baseline method, see Chapters 6 and 7 for analysis and discussion of baseline methods and associated impact estimates).

[20] As noted in Chapter 7, half of PG&E's DBP impact for summer 2004 came from customers that are also signed up for an interruptible program.

Conflicting Information on Customer Need for Additional Technical Assistance

The extent of customer need for DR technical assistance is unclear based on the empirical and anecdotal findings in this evaluation. In close-ended surveys, customers have tended to indicate that they are knowledgeable about their DR options and do not volunteer requests for technical assistance when asked what more can be done to encourage their participation. In addition, we are unaware of any customers that went through the entire process of receiving the Technical Assistance incentives designed for CPP and DBP participants.[21] Nonetheless, in our in-depth interviews with customers and site visits associated with the sub-metering portion of this evaluation, we have found numerous cases where customers either asked for our support or were clearly in need of technical support to develop a DR implementation plan. The Technical Assistance Incentives as originally designed clearly pose risks onto customers and have not worked. General DR is also available to customers through the CEC's Enhanced Automation project, which includes customer case studies, a technical guidebook for facility managers, and a business case guidebook for management decision makers. Despite the lack of receptivity to the 2004 Technical Incentives, there is evidence that a modified technical assistance approach that includes site-specific support could provide value to participants and lead to increased DR impacts.

3.1.2 2004 CPP-DBP Accomplishments

Although significant challenges to the DBP and CPP programs exist with respect to their ability to make large contributions to the overall price-responsive DR goals established by the CPUC, it is important to emphasize the many accomplishments were achieved in 2003 and 2004. These accomplishments include:

- Significant Increases in Program Awareness and Familiarity
- Design and Implementation of Extensive Program Processing Systems
- Customer and Utility Experience Gained from Program Experience
- Utilization of Market and Evaluation Feedback to Modify Programs

Significant Levels of Program Awareness and Familiarity

As noted in our March Phase I Report, PG&E and SCE account managers succeeded in contacting all or most of their eligible customers before the end of 2003, while SDG&E chose to begin its full-scale, direct marketing campaign in 2004. All of the utilities attained significant achievements in raising awareness for these new programs. Levels of familiarity reported for the DBP and CPP programs were reasonably high and similar (64 percent versus 61 percent of

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[21] The Technical Assistance incentive offered CPP or DBP participants with a cash incentive of up to $50 per kW of curtailable on-peak load reduction to cover the cost of load reduction feasibility studies conducted by CEC-approved professional engineers. Customers were to receive half the incentive upon certification by the engineer; to receive the other half, customers must provide actual load reductions averaging at least 50 percent of the certified amount during CPP or DBP events.

the market, respectively), based on our market survey conducted in spring 2004. The main source of information about these programs came from personal contact with their utility.

Design and Implementation of Extensive Program Processing Systems

Both the DBP and CPP programs require fairly extensive program processing systems and procedures to implement. The utilities developed and implemented these new and often complex systems, particularly for DBP, effectively. Although there were some problems that occurred with these systems they were for the most part minor and well within the range of what would be expected in developing and deploying these types of systems.

Customer and Utility Experience Gained from Program Experience

In viewing the results achieved by these programs to date, it is worth bearing in mind that any new product/service adoption takes time. In the beginning, customers would be expected to view the DR programs as complex, but this perception may decrease over time. One program manager drew a parallel between the current reluctance to embrace DR and the early days of DSM, when it took time for customers to adapt to this new way of looking at their energy usage. It is important to see learning as part of the process of rolling out new offers – at regulatory agencies, utilities, and customers. It is difficult to "get it right the first time", and there is evidence from other parts of the country of programs that have been tried for three years and are still not achieving their hoped-for impacts (e.g., NY ISO Day-Ahead Pricing Program), while other programs are doing better than expected. We believe that both customers and utilities have obtained valuable experience through the summer 2004 events that did occur. Of course, as discussed elsewhere in this chapter, more learning and experience is needed to assess program performance and future prospects so it is important to increase the number and type of events required of program participants in 2005.

Utilization of Market and Evaluation Feedback to Modify Programs

We believe another successful aspect of the 2004 DBP and CPP programs was WG2's focus on using real-time evaluation and program managers own market feedback to assess and modify programs as quickly as possible, both within 2004, and for 2005. It has been difficult in the past with DSM programs to obtain feedback and regulatory approval for program changes quickly enough to make major modifications from one program year to another. Typically, it takes two program years to make changes as ex post evaluations are completed a year after the close of the program year. WG2 and the CPUC worked hard to put a process same-year feedback into place along with regulatory filing dates to enable minor modifications for this program year and possibly major changes for 2005. Of course, there are significant challenges associated with conducting an evaluation like this one on a real-time basis, particularly an impact evaluation across three utilities that involves hourly load data and replication of settlement and other baseline load estimation methods. Nonetheless, the process has been implemented as designed and the utilities have actively used the evaluation results along with their own information to propose program modifications aimed at increasing the contribution of these new programs to help meet the CPUC's price-responsive demand response goals.

3.1.3 DBP-CPP Recommendations

In this section we present our recommendations for the DBP and CPP programs. Readers should note that the presence of a recommendation in this report does not mean that the utilities or other parties are not already pursuing or proposing similar or closely related actions, indeed there is overlap among our suggestions and those submitted by the utilities in their October 15th filings and as well as parties comments.[22] Our recommendations are to:

- Quantify Value of DR Benefits and Conduct DR Program Cost-Effectiveness Analyses
- Consider Tradeoffs Associated with Modifying Event Triggers to Increase Probability of Day-Ahead and Day-Of Events
- The IOUs Should Work with the CPUC on the Best Approach to Adjusting the Current Method for Reporting Program Impacts
- Consider Increasing or Modifying the Structure of the Financial Benefits of Participation, Subject to Cost-Effectiveness Considerations and Other Constraints
- Allow Customer Aggregation for DBP
- Reduce Minimum DBP Bid to 50 kW for Smaller Customers and Consider Tiered Bidding Minimum by Size
- Encourage Participants to Prepare Bidding Strategies in Advance, Request Courtesy Notification, and Provide Backup Contacts
- Consider Tradeoff Associated with Increasing Amount of Time Between Notification and Bidding
- Change PG&E Day-Of DBP Program to Replace Committed Load Approach with Bidding
- Consider Expanding DBP Program Eligibility to Direct Access Customers
- Continue CPP Bill Protection and Emphasize in CPP Marketing
- Increase Attractiveness of Technical Assistance, Subject to Cost-Effectiveness Considerations
- Continue Collaborative Efforts to Achieve Price-Responsive DR Goals

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[22] See PG&E, SCE, and SDG&E October 15, 2004 filings, Rulemaking 02-06-001, proposing 2005 program descriptions and budgets.

Quantify Value of DR Benefits and Conduct DR Program Cost-Effectiveness Analyses

It is imperative that a DR valuation framework be agreed upon and cost-effective analysis completed so that benefit-cost scenario analysis can be conducted to inform decision-making regarding these programs. A threshold concern about the CPP and DBP programs is whether these voluntary programs with the current levels of customer financial incentive and participation levels are cost-effective or under what conditions in the future they could be. It will be difficult for policy makers to make informed decisions about changes in the program prices and payments without an analysis and estimate of DR value (that includes future price and reliability risks) and analysis of current program costs and benefits.

Consider Tradeoffs Associated with Modifying Event Triggers to Increase Probability of Day-Ahead and Day-Of Events

A valuable opportunity to definitively assess the performance of the DBP and CPP programs in summer 2004 was lost due to the fact that few program events were triggered.[23] As discussed elsewhere in this evaluation, the DBP tests for SCE and SDG&E resulted in only a small percentage of participants taking action. From an evaluation perspective, it would be preferred to have a guaranteed minimum number of program events. There are also program benefits of ensuring program events, in particular, to increase the certainty of the estimated DR resource availability and maintain customer interest. Of course, an obvious downside to triggering a minimum number of events, even if external conditions do not warrant them, is that program participants will become skeptical of the basis for the programs and may take future event calls less seriously. This is especially true if the primary motivation for customers' actions is maintaining system reliability rather than capturing bill savings. In addition, program cost-effectiveness can be negatively impacted, for example, if the DBP is called even if the market price trigger is not reached, the customer payments will exceed the avoided cost benefits.

The IOUs Should Work with the CPUC on the Best Approach to Adjusting the Current Method for Reporting Program Impacts

As discussed in several chapters of this report, SCE's Day-Of DBP test events had very small percentages of bidders (roughly 5 percent of participating accounts bid in each event). Similarly, only a modest fraction (roughly a quarter) of SDG&E's DBP accounts bid in its two test and one actual event. Admittedly, as a purely voluntary program there is little cost to keeping these participants on the program. In addition, although some of these customers expressed very little interest in actively participating,[24] it is possible that they might become more motivated if they perceive greater system reliability needs in the future. In addition, it is extremely difficult to draw conclusions about the SCE DBP group given that only test events occurred. Our research indicates it is unlikely that the entire pool of DBP participants are likely

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[23] An exception was SCE CPP for which all 12 events were triggered. However, as discussed elsewhere, there were only 8 participants in this program so it contributed little to the evaluation learning opportunity.

[24] One-third of 2004 DBP non-bidders indicated that they were somewhat or very unlikely to bid in future events.

to bid; however, the DBP program managers believe that these customers will engage if they perceive there is a significant reliability-based need.

The low levels of participation in the SCE and SDG&E DBP test events makes it difficult to estimate the size of the DBP DR resource during a period when resource needs and availability are of concern to policy makers and resource planners for summer 2005. We recommend that the utilities consider the results in this evaluation, along with their own direct experience with program participants, and work with the CPUC to adjust the current program impacts reported. In addition, the CPUC and utilities should consider segmenting their estimates of resource availability for DBP based on day-ahead versus day-of events. Evidence in this evaluation indicates that only a sub-segment of participants are able and currently prepared to participate in day-of events. Increased information and technical support could increase the portion of the participant population that is day-of ready for next year.

Utilities also should screen new participants to make sure they understand program rules, requirements, and expectations. Clear explanation of program requirements, including notification times for bidding, minimum bids, and baseline methods, should be emphasized

Consider Increasing or Modifying the Structure of the Financial Benefits of Participation, Subject to Cost-Effectiveness Considerations and Other Constraints

The current levels of financial incentive for participants in both the CPP and DBP programs appear insufficient to motivate significant portions of the market to actively participate in the programs. Only 1 percent of eligible accounts participated in the CPP for summer 2004, however, by design, roughly 50 percent of eligible customers should benefit on the rate without making any change in their load shapes. For most of these, however, the level of benefit is very small, on the order of 1 percent of their annual bill. According to the utilities' rate analyses, even with peak load reductions of 20 percent during CPP events, PG&E and SCE customers that benefit would save only about 2 percent as compared to their annual bills. This level of savings, even with the bill protection incentive, is simply not motivating significant numbers of customers to participate. This may be partially attributable to customer concerns over the risk and stability of the rates themselves given experiences with changing rates and programs dating back to the energy crisis.

We understand that increasing customer benefits from the CPP tariff is not easy given the constraint of revenue neutrality, nor may all stakeholders agree that this is justifiable given current low market prices. Of course, if the CPP becomes a default tariff, then the issue of motivating voluntary participants becomes moot.

For DBP, as discussed previously, the total level of financial compensation for participation is also modest as compared to customers' total annual electricity costs. However, another issue is that there is a fixed cost associated with participation in a bidding type program. Customers will typically want to have a load reduction plan, process for implementing the plan, analysis of benefits and costs, and bidding strategy. Without any certainty of how many events will be called, it may be difficult for customers to commit to investing the fix costs necessary for successful participation. In addition, customers may sign up for the program but not be engaged in active participation. For these reasons, some programs, like the CPA DRP, and several programs in other regions, also include a capacity payment.

DR programs nationally are striving more and more to address both reliability and price concerns. Partly this is because the two issues often are intertwined, but partly it is also a question of how customers are affected by DR programs, in that they tend to view both issues similarly because they are taking the same curtailment actions under both issue regimes. Thus, customers' desire (as reported by program managers in our review of non-California DR programs) is for simpler, more unified programs that include some element of a capacity payment.

Allow Customer Aggregation for DBP

Currently, there appear to be several multi-site customers with interest in and capability to provide demand response. For example, some of these customers developed capability as part of the CEC/ICF small commercial demand response program. The individual load reduction at these is too small to meet the 100 kW bid minimum, however, and the costs of working with individual sites to the utilities would be high. Customer aggregation for load curtailment has occurred in previous California utility programs dating back to the 1980s and was recommended by several parties in the summer 2004 WG2 workshops (including ASW Inc. and the utilities). We support allowing aggregation to help increase program participation in DBP.

Reduce Minimum DBP Bid to 50 kW for Smaller Customers and Consider Tiered Bidding Minimum by Size

Reducing the DBP bid minimum to 50 kW would give medium-sized customers an opportunity to participate in the program. However, we urge some caution with regards to making 50 kW the minimum for all size customers. For larger customers, observing 50 kW of load reduction is very difficult given the limitations of existing baseline methods. On the other hand, larger customers are unlikely to make small bids given the effort required versus savings. A 50 kW bid minimum may also only motivate multi-site customers to participate since the savings for individual customers would be very small. Allowing aggregation may capture a portion of the benefit associated with lowering the bid minimum.

Encourage Participants to Prepare Bidding Strategies in Advance, Request Courtesy Notification, and Provide Backup Contacts

The utilities' notification systems operated effectively. However, some customers were not prepared to place Day-Of bids in the DBP program because they did not have bidding strategies prepared in advance or did not respond to the utility notification in time. Participants should be encouraged to prepare their bidding and load reduction plans in advance of the summer. In addition, not all customers signed up for the additional courtesy notifications available or provided backup contacts. Customers should be reminded to avail themselves of these program services and to train backup contacts to place and execute bids as appropriate.[25]

[25] It is unlikely backup contacts will be comfortable placing and executing bids until primary contacts have more experience in the program and can provide proven processes that can be followed in their absence.

Consider Tradeoff Associated with Increasing Amount of Time Between Notification and Bidding

A number of participants indicated that they were more likely to make DBP bids if they had more time between event notification and bid submittal. However, we recognize that the value of the load reductions taken is closely related to how quickly they are realized, particularly, for day-of events. It may be worth exploring whether a slightly longer period for bid submittal could be permitted but perhaps with the incentive tiered based on how quickly the bid is received.

Change PG&E Day-Of DBP Program to Replace Committed Load Approach with Bidding

PG&E has requested to change its committed load approach to enable bidding for the Day-Of DBP event consistent with the other utilities. We concur with the need for this change.

Consider Expanding DBP Program Eligibility to Direct Access Customers

Almost all customers over 200 kW for PG&E and SCE and 100 kW for SDG&E are eligible for the DBP program with the notable exception of direct access customers. The exclusion of direct access customers takes several thousand megawatts of load out of program eligibility. Assuming parties can resolve differences over logistical challenges, expanding to direct access would provide a significant pool of additional DBP participation candidates.

Continue CPP Bill Protection and Emphasize in CPP Marketing

The Bill Protection Incentive was intended to assure participants they would not pay more under the CPP tariff than they would have under their otherwise applicable tariff (OAT) for the first 14 months they participate in the CPP program. Originally, to receive the incentive, the customer needed to reduce critical peak usage by an average of 3 percent for each CPP event during those 14 months. In June 2004, based on utilities' request to modify the incentive in their March 31 filings, the 3 percent requirement was eliminated.[26] Since much of the marketing for the CPP program occurred in late 2003 and early 2004, it is not clear whether most customers are aware that they can try the CPP for one-year without risk. Marketing efforts should emphasize the no-risk aspect of the CPP to encourage greater participation.

Increase Attractiveness of Technical Assistance, Subject to Cost-Effectiveness Considerations

Although many customers do not actively seek DR technical assistance, there is evidence that some customers could greatly benefit from free, easily available DR support that provides site-specific analysis and strategies. In particular, commercial customers more than industrial or even institutional are in need of such support. As part of our sub-metering recruitment efforts and associated on-site surveys, we encountered several cases in which customers were unsure of the kinds of DR actions they could implement, how they could implement them, and what impacts would result. Care should be taken to develop technical support services that are cost-effective; bundling DR technical support with energy efficiency audits may be one way to do

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[26] *Administrative Law Judge's Ruling Approving 2004 Schedule And Plan For The Statewide Pricing Pilot Evaluation And Customer Research Activities And Establishing Process For Evaluation Of Proposed 2005 Price Responsive Demand Programs*, Rulemaking 02-06-001, June 2, 2004.

this so that fix costs are spread among activities with multiple benefits. Technical support services should be targeted at program participants who are highly motivated to improve their DR capability and associated program activity levels.

Continue Collaborative Efforts to Achieve Price-Responsive DR Goals

If the CPUC maintains its current price-responsive DR load reduction goals, difficult policy choices regarding the future of the voluntary CPP and DBP appear inevitable. These choices include, among others, increasing financial incentives, keeping the current incentives as they are and risking continued low levels of participation, making a CPP tariff mandatory, or eliminating the programs altogether and starting over. Without an agreed upon valuation of DR benefits and associated cost-effectiveness analysis, and more real-world experience with the programs across a wide range of price and system reliability needs, a decision to eliminate the programs seems premature. Elimination, instead of modification, would also re-enforce the perception of many customers that these programs are unstable and could lead to further reluctance to participate in future programs. Other options include reducing the goals or making CPP mandatory rather than voluntary. Moving to a default CPP, as suggested in the CPUC's December 8, 2004 ACR (see footnote 1), could greatly simplify the DR landscape and dramatically increase the likelihood of reaching the Commission's price-responsive DR goals. These are obviously policy decisions and certainly not within the charge of this evaluation to resolve. We simply encourage the CPUC, utilities, and other stakeholders to continue working together toward a comprehensive approach to demand response that will increase the likelihood of achieving the CPUC's price-responsive goals.

3.2 ISSUES ASSESSMENT – RELIBILITY-BASED DR PROGRAMS

This section presents the issues identified by a qualitative assessment of reliability-triggered interruptible rate programs offered by PG&E, SCE and SDG&E. These programs have been in place for several years and the traditional interruptible programs offered by the three utilities have been in place for over a decade. WG2 decided to review these programs in addition to the original set of innovative price-based DR programs that were being implemented for the first time by the utilities in 2004. However, the scope of this part of the evaluation was much smaller than the level of effort for the CPP and DBP programs. The interruptible program evaluation scope included only interviews with utility program managers, review and documentation of program features and call history, and in-depth interviews with a small sample of 15 participants across all of the reliability program types and three IOUs. Full results are presented in Chapter 9.

3.2.1 Summary Background on Reliability-Triggered Programs

Five programs are summarized in this section and described and reviewed in greater detail in Chapter 9:[27]

[27] The descriptions in Chapter 9 are summaries only, so the reader is advised to consult the utilities' tariffs for complete details.

(1) Traditional non-firm rates ("Non-firm"), including PG&E's Schedule 19 and Schedule 20 non-firm service schedules; SCE's I-6 non-firm schedule and SDG&E's AL TOU CP (including Schedule EECC) service

(2) Base Interruptible Program (BIP)

(3) Optional Binding Mandatory Curtailment program (OBMC)

(4) Scheduled Load Reduction Program (SLRP) and

(5) Rolling Blackout Reduction Program (RBRP).[28]

The task of evaluating reliability-triggered interruptible programs was assigned a limited scope, as the broader evaluation focused the majority of its resources more on price-triggered programs. As such, the limited interview activities undertaken of program managers and customers were designed to summarily characterize the programs and compile qualitative feedback on the programs' experience from customers' and program staffs' perspectives. These interview efforts were supplemented by development of a history of the programs' curtailment events, to help understand the programs' history, and a program feature comparison spreadsheet to use in future efforts to further rationalize and integrate a portfolio of DR programs.

Four data collection efforts were undertaken:

1. Compile data on interruptible program events for the four-year period covering 2000-2003. Standard participation and impact reports from each utility were the source for these data.

2. Compile data on interruptible program features, utilizing tariff documents and marketing collateral as the primary data sources.

3. Gather qualitative information from program managers through telephone interviews.

4. Gather qualitative information from a small sample of fifteen participants in the Traditional Interruptible, Optional Binding Mandatory Curtailment and Base Interruptible Programs.

3.2.2 Traditional Interruptible Programs – PG&E, SCE and SDG&E

This section summarizes program structure and then discusses key issues that were identified in the analysis described in Chapter 9 of this report.

[28] RBRP is offered only by SDG&E.

Summary Traditional Interruptible Program Description

These programs began in the 1980s. PG&E offered a "Non-Firm" rate based on its E-19 and E-20 rate schedules. This rate was open to all customers eligible for the E-19 and E-20 rate until 1992, when capacity surpluses led to it being closed to new customers, though existing customers were allowed to continue on the rate through name changes and moves. Beginning in 2004 the rate has been closed even to existing customers if they have changed the account name or moved. Both direct access and bundled customers are enrolled.

The rate provides both rate discounts (in the form of lower demand and energy charges, year-round) and $/kWh penalties applied to excess energy used above the contract firm service level when an event is called. Up to five "pre-emergency" curtailments, each lasting no more than 5 hours, may be called annually. Emergency curtailments may last up to 6 hours, or until PG&E notifies the customer that the period has ended if less than 6 hours, with a 100-hour annual cap. The general conditions for pre-emergency curtailments are based on a mid-morning temperature forecast of above 105 degrees (F) in the Central Valley. Emergency curtailments are called according to Stage 2 and Stage 3 system reliability conditions. A 30-minute notification is provided to customers, communicated via telephone, email or other communications means.

SCE also began offering its Large Power Interruptible service under its I-6 rate schedule in the 1980s. The rate continues to be open to "new" loads and "new" customers, but is closed otherwise. Both direct access and bundled customers with new loads or are new to the SCE service area are eligible.

Customers eligible for the Large General Service TOU-8 rate schedule may take I-6 interruptible service provided they meet the new-load requirements. The customer's firm service level may be zero and must be at least 500 kW less than the maximum peak demand. Like the PG&E program, the SCE rate provides both rate discounts (in the form of lower demand and energy charges, year-round) and $/kWh penalties applied to excess energy above the contract firm service level.

Curtailments are called during Stage 2 or Stage 3 system conditions, on 30-minute notice. A remote terminal unit communications system in conjunction with telephone lines is used, and for which there is a fee to cover installation and maintenance costs. Curtailments are limited to 1 event per day, 4 events per calendar week, and 25 events annually. Events are limited to a maximum of 6 hours and total hours of interruption are limited to 40 hours per month or 150 hours per year. Interruptions may be called at any time of day or week throughout the year. Noncompliance penalties ranging from $7.20-$9.30 per kWh of excess energy (demand above Firm Service level times hours in excess of that demand).

The "traditional" interruptible rate offered by SDG&E is different than those offered by PG&E and SCE. Where those utilities' traditional non-firm programs have contractually based firm service levels and a discount/penalty scheme applied to demand and energy usage, SDG&E's AL TOU CP rate schedule is actually a time of use program. No firm service levels are specified, nor are there particular discounts or penalties. Instead the rate changes according to system conditions with a 1.80 cent "signal price" that applies to a time-of-use energy charge during critical peak periods (events) defined by Stage 2 or Stage 3 system conditions.

SDG&E customers with self-generation are eligible for this rate, with no minimum demand or minimum impact requirements. The customer may operate their self-generation facilities at any time while on the rate.

Traditional Interruptible Programs – Findings

When these programs were first established during the 1980s and 1990s, the supply situation was such that they were called infrequently. This situation changed in 2000 and 2001 when both the number and duration of called events spiked. A large number of customers left the program due to frequent events and the risk of penalties if reductions were not achieved. Across all utilities, the number of customers participating in these programs fell by approximately one half. Issues identified that are potentially relevant for consideration when designing or refining a portfolio of DR programs are discussed below.

Evidence that Customers Remaining on the Interruptible Programs are Prepared for Modest Numbers of Reliability Calls -- Interviews with both customers and program managers indicate that the customers that remain on the program could be viewed as the "survivors" of this intense period of frequent events. They are customers that are likely to have a higher tolerance for frequent events, and the ability to adjust operations during events. While this belief is held by program managers and re-enforced by customer interviews, it has not yet been proven since there has not been a meaningful series of events called since 2001. However, supporting the view that the remaining customers likely comprise a reliable resource is the fact that customer interviews[29] indicated that they expected to be called at least several times a year.

Customer Migration Away from Traditional Programs to Newer, More Aggressively Marketed Programs Might Reduce the Reliability Resource -- There is limited ability for customers to opt into the traditional interruptible rates programs offered by the utility and there is the opportunity for these customers to switch to other price-triggered programs that are being given greater attention (at least in terms of marketing) such as the CPP or DBP programs. Interviews with program managers questioned whether migration out of traditional interruptible programs is a good idea. Any substantial transition could dilute the depth of this resource and move customers into programs that may have lower performance levels. Maintaining the traditional interruptible programs as a "deep reserve" in case supply resources once again become scarce was seen by program managers as a reason not to change the existing programs and, in fact, to retain their basic design. Of course, some customers have chosen to participate in both interruptible and DBP programs. However, because the interruptibles take precedence in system emergencies, adjustments may be needed to net out the participation of interruptible participants in the DBP for emergency days.

Customers Understood the Concepts Associated with Reliability-Triggered Programs Better Than the Concepts Underlying Price-Triggered Programs – In general, customers find it easier to understand the concepts associated with system reliability and the linkage to reliability-triggered programs. Price-triggered programs were more difficult to understand in terms of benefits to the system, the utility and to the customer. Simply stated, system constraints and

[29] Note that only 15 interviews were conducted, thus, this is an anecdotal not statistically reliable sample.

supply availability that result in Stage 2 and Stage 3 alerts along with the possibility of outages were viewed by customers as immediate, real threats that they were helping to avoid.

Customer Acceptance is High with the Traditional Interruptible Programs -- Participating customers perceived that the utility was trying to address long-term resource requirements through these programs. This resulted in a view that the customers were, in essence, partnering with the utility to address critical needs. As a result, customers would seek out options to participate in the programs and make reasonable adjustments *if* there is the belief that they are working with the utilities to address underlying resource needs.

Account Representatives are Viewed as a Key Element of the Traditional Interruptible Programs – Among the customers interviewed, a pro-active relationship with the utility is critical to build trust and ensure program readiness. Account representatives are viewed by some as having been a key element of this relationship. Good representatives are highly valued by those customers interviewed. Other means can be used to augment the account representatives' productivity, as well. This could include web sites to log in and see if their electronic event notice acknowledgement has been received by the utility, and information on the likelihood of forthcoming events (even though this creates problems for baseline estimation).[30]

Operational Processes for Traditional Programs Seen as a Strength -- The contract and operational processes for these programs are mature and relatively streamlined. This was a strength cited by program managers and customers when comparing these programs to the newer DR programs.

3.2.3 Base Interruptible Program (BIP)

Summary BIP Program Description

The Base Interruptible Program (BIP) is a relatively new program developed in 2001 that offers customers demand charge credits for reducing load to a specified firm service level. The program is open to both bundled and direct access customers on large commercial/industrial rates except PG&E, which offers it only to bundled customers. Like the traditional interruptible programs PG&E and SCE have, BIP is based on a firm service level, but it has different impact requirements: committed minimum reductions of either 15 percent of load or 100 kW impact (whichever is higher) are required. Demand charge credits of $7.00 per kW-month of load impact are provided for all load above the firm service level established for the customer (the firm service level being established on the basis of average monthly demand), and significant penalties are imposed on excess energy taken above the firm service level.

BIP events are called on a 30-minute notice, sent via email and pager and with internet web site confirmation back by the customer, when the utility is notified by the CAISO of Stage 2 or Stage

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[30] The issue of utility acknowledgment of the receipt of the event notice by the customer came up a number of times. There is concern that given 30 minute notification periods and the potential for the notification to not be picked up by a pager, or by a cell phone, or via e-mail was of concern. The rationale was this might cause penalties to be incurred and result in missed opportunities for the customer.

3 system conditions. Curtailments are limited to one event per day up to 4 hours, 10 events per month and 120 total hours annually. A noncompliance penalty of $6.00 per kWh is assessed on excess energy used above the firm service level during events.

BIP Program – Findings

BIP Program Has Reasonably High Resource Potential Compared to Traditional Programs -- The interviews with program managers indicated that they viewed this program has having good potential as an alternative to traditional programs, particularly if appropriate financial incentives were included. Incentives for BIP were not viewed as being generous, while the penalties were viewed as being onerous.[31] The suggestion was made that the BIP program could be expanded by lowering the minimum customer eligibility level from 500 kW to 200 kW.

BIP Program Processes Seen as Working Successfully but the 30-Minute Notification Window is a Constraint -- Process testing has been performed regularly and program managers report no significant issues. Experience with the 30-minute notification window is lacking due to the paucity of BIP events, although customers interviewed for both the traditional and BIP programs believed that a 60-minute notification period would be of substantial benefit to them because of their operational logistics.

Administration of the BIP Program Poses Few Problems -- The BIP program was reported to have fewer compliance problems than the traditional programs, and has a simple contract like the traditional interruptible programs.

3.2.4 Optional Binding Mandatory Curtailment Program (OBMC)

Summary OBMC Program Description

The Optional Binding Mandatory Curtailment (OBMC[32]) program is another recent development resulting from the energy crisis of 2000-2001. The program offers blackout avoidance, when the ISO declares rotating outage, in return for up to 15 percent reduction in circuit load during events. The program is unique in its focus on the circuit, or feeder, as the basis for the load being reduced, instead of a building or campus situation within a circuit. Thus, there is a cooperative aspect to the program in that customers who wish to participate in OBMC may need to coordinate load management with other customers on the circuit in order to meet the curtailment requirements.

The program requires an OBMC curtailment plan be submitted that shows how the circuit loads will be managed in 5 percent increments up to the 15 percent maximum curtailment level. The plan must be updated annually. Customers have 15 minutes to respond before becoming subject to the program's non-compliance provision. There are no limitations on the number or duration of events.

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[31] The BIP program was viewed as having lower incentives than the traditional programs, yet roughly equal and substantial penalties.

[32] PG&E also fielded a pilot version, POBMC.

OBMC Program – Findings

The Requirement that Entire Circuit Load be Reduced Poses Complications for Some Potential Participants -- The program can present significant challenges in practice due to the requirement that the entire circuit load must be reduced. When there are multiple customers on the circuit, there may be limited interest among some customers to participate. However, when a circuit is dedicated to one customer, this complication disappears.

Lack of Events Creates Some Uncertainty Regarding for the Operation of Program Processes During an Actual Event -- The lack of events has prevented a full test of the program. The 15-minute notification window is tight and may present problems for customers. Communications was a concern of all customers[33] across all programs and, with a 15-minute window, the communications system mush be very robust.

Administration of the OBMC Program Seen as More Complex than Other Programs -- Contracts for the OMBC were cited as being somewhat more complicated and that simple changes, e.g., the name change of the customer can require almost full reprocessing of the agreement through different departments.

3.2.5 Scheduled Load Reduction Program (SLRP)

Summary SLRP Program Description

The Scheduled Load Reduction Program (SLRP) is a legislated rate program established in 2001. It offers a credit, and no penalties, for bundled-service-only customers who commit to reduce load by at least 15 percent, with a 100 kW minimum. Customers who participate choose from one to three four-hour periods, during weekdays they select, in which to commit load reductions. The credit offered is $0.10/kWh for reduced energy below the baseline established for each customer. Load shifting to peak periods is prohibited.

SLRP Program – Findings

Program Viewed as Not Being Appropriate for the Current Environment -- The interviews with program managers indicated general agreement that this program, though conceptually simple,[34] is strategically out of synch with the intent of demand response programs. That is because the SLRP option menu structure allows (indeed, locks in) load reductions during times when they often are not needed from a system reliability perspective, or even a price perspective. Further, customers receive the same 10-cent per kWh credit regardless of when they deliver impacts, so the price signal to customers is misaligned as well.

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[33] Program managers did report that, on occasion, customers had problems confirming notification receipt. One customer noted that they keep four pagers active and still do not get the page sometimes when communications tests are called.

[34] Flat incentive, no penalty except program dismissal, presumably routine load scheduling, no notification hassles, etc.

Customer Acceptance of, and Enrollment in, the SLRP Program is Low -- Only 16 accounts are enrolled in the program across the three utilities, all but one being in SCE's service area. One issue is that scheduling loads as large as the 100 kW minimum required for the program can be difficult, whereas smaller loads, represented by such end uses as lighting and HVAC equipment, may be more amenable to such a program – but they are ineligible unless the customer is able to coordinate their aggregate impact. One manager opined that customers would be better off participating in the DBP program instead.

3.2.6 Rolling Blackout Reduction Program(RBRP)

Summary RBRP Program Description

The Rolling Blackout Reduction Program (RBRP) is offered only by SDG&E. It offers customers with self-generation an opportunity to reduce the severity of rotating outages called under Stage 3 system conditions. Unlike OBMC it does not exempt participating customers from rotating outages altogether, but instead provides a credit for energy produced by the customer's backup generator during events. Various standby generation requirements must be met for safety and interconnection reasons.

The credit offered is $0.20 per kWh for energy reduced, when the customer achieves their 15 percent demand reduction (100 kW minimum). Credits are paid only for those hours during which the entire obligation is met (no hourly partial credit). A rolling 10-day baseline is established against which the customer's generator output is measured, with an initial test according to program rules conducted to certify the generator output. Customers must respond to event notification within 15 minutes. Notification is via email and pager.

RBRP Program – Findings

RBRP Program is Targeted at a Specific Set of Customers -- Program Targeting – The program is a simple, targeted offer which is focused on customers with at least 100 kW of backup generation capacity.

Program Processes Believed to be Appropriate, but not Fully Tested -- The 15-minute notification period is believed to be adequate for customers to start their generators and periodic tests are performed to assess readiness; however, there have been no events called and a true operational test has not been tried.

3.2.7 Reliability-Triggered Programs -- Recommendations

Maintain the Most Successful Features of the Existing Reliability Programs If Programs are Revised for 2005 -- These reliability programs have been in existence for at least several years and the traditional interruptible program has been around since the 1980s. Customers are still participating in these programs despite the numerous events called in 2000 and 2001. A recent event call by SCE in 2004 yielded a utility-reported reduction of approximately 620 MW. The features of these programs where payments (at least some) are made up front and often year round, along with the simple administrative processes, should be considered when or if developing new or revised programs.

Possible Changes to these Reliability-Triggered Programs – Several possible modifications were suggested:

1.) An assessment of whether the notification periods actually have to be 30 minutes for the traditional interruptible and BIP programs, and 15 minutes for OMBC and RBRP programs would be useful. Expanding this notification period to 60 minutes and 30 minutes was believed by customers to ease a number of concerns they have about responsiveness and communications. However, as mentioned in regards to the same issue for DBP, we recognize that the value of the load reductions taken is closely related to how quickly they are realized, particularly, for day-of events. It may be worth exploring whether a slightly longer period for notification could be permitted but perhaps with the financial benefits tiered based on how quickly the action is taken.

2.) The BIP program was viewed as having increased potential particularly if it could be made somewhat more financially attractive – similar to the traditional interruptible program, and if the eligibility level was lowered from 500kW to 200kW.

3) The SLRP program was not believed to meet the needs of a DR program in terms of reducing load to meet system needs (or avoid high prices) and should be discontinued.

4) Consider simplifying the portfolio of reliability programs.

Manage any Migration of Customers to Newer Price-Triggered DR Programs to Maintain the Availability of Reliability Resources – Several of the traditional interruptible programs have been used to meet system needs and the customers that remain on those programs are likely to be responsive. For example, the BIP, OMBC and RBRP programs have been process tested with few problems found. There may be other reasons that the CPUC or other parties wish to maintain or modify these programs. Engaging participants in these programs in price-responsive DR programs could increase the size of the price-responsive programs but should consider ways in which the reliability-based resource is also maintained.

Field Test All DR Programs in Addition to Process-Only Testing -- All programs should be field tested, not just process tested, to ensure the reliability of response and help customers be prepared for situations in which the capacity is needed to meet system constraints.

3.3 ISSUES ASSESSMENT – CALIFORNIA POWER AUTHORITY DEMAND RESERVES PARTNERSHIP (CPA-DRP)

In this section, we summarize the key findings regarding the California Power Authority Demand Reserves Partnership (CPA-DRP) and offer recommendations for that program. WG2 decided in early summer 2004 to include the CPA-DRP in this evaluation. However, the scope of the DRP part of the evaluation, similar to the effort for the reliability programs, was much smaller than the level of effort for the CPP and DBP programs. The CPA-DRP scope included only program manager interviews, interviews with aggregators, and very small number of interviews with participating end users. Full results are presented in Chapter 10.

3.3.1 CPA/DRP FINDINGS AND RECOMMENDATIONS

The following are key findings of the CPA-DRP process evaluation.

- The Program Had Significant Participation Through The Summer Of 2004 Despite Uncertainty, Reduced Incentives, And Shifting Rules Of Participation
- Program Uncertainty Hampers Marketing Effectiveness
- Capacity Payments and DA Eligibility Attract Significant Load, and Aggregators Expect More Now that Program Has Stabilized
- DWR Continues to Dominate Participation in the Program
- Multiple Players Add to Program Complexity, But Appear to Benefit Customers

The Program Had Significant Participation Through the Summer of 2004 Despite Uncertainty, Reduced Incentives, and Shifting Rules Of Participation

The DRP program in 2004 faced an array of obstacles that would appear to make it a severe marketing challenge: the price paid to participants had declined for each of the past two years, conditions of participation had become more difficult, the sponsoring agency had been on the verge of going out of existence, and there were no formal contracts in place describing just what participants are expected to do and when or how they are expected to do it. In spite of these obstacles, the aggregators who are responsible for finding and enrolling participants managed to attract a number of customers – both DA and bundled – who remained with the program throughout a potentially disastrous summer.

Program Uncertainty Hampers Marketing Effectiveness

The program has gone through frequent changes since its inception; uncertainty has discouraged many customers from participating and made it very difficult for aggregators to market the program. Program managers, aggregators and customers agree that the most urgent need now is to bring stability to the DRP program; who will run the program, and what will be the payment and other operational terms of participation. The program will still be complex, but most customers say they are likely to stay with the program if stability can be attained.

Capacity Payments and DA Eligibility Attract Significant Load, and Aggregators Expect More Now that Program Has Stabilized

Participants were strongly motivated by the capacity payment offered through the program, noting that this feature distinguishes the DRP program from other options such as DBP. Other features attracting customers include the eligibility of DA customers and the lack of out-of-pocket penalties under the program terms offered by the aggregators. Almost all participants complained about the decline in the capacity payment over the past two summers, and a few said further reductions might call their participation into question. Most, however, expect to stay with the program, and the aggregators interviewed expressed confidence that they would be able to attract new participants to the program now that program provisions had been finalized.

DWR Continues to Dominate Participation in the Program

Acting as its own aggregator, DWR itself dominates participation in the program, accounting for well over half of the nominated load in recent months. Opportunities appear to exist to expand participation by other customers, with particular emphasis on segments such as water agencies that have significant untapped potential but are reluctant to participate until the program has demonstrated stability and effectiveness. Greater utility involvement in the program may also increase the pool of customers willing to participate.

Multiple Players Add to Program Complexity, But Appear to Benefit Customers

Having multiple players adds to program complexity, but competition among aggregators appears to work to the advantage of customers; a specific example is the extent to which aggregators structure agreements with customers to minimize exposure to out-of-pocket costs – whether for penalties or fixed fees associated with the aggregator's services.

3.3.2 CPA-DRP Recommendations

The following are recommendations for the CPA-DRP program.

- Create Organizational Stability Well In Advance of Summer 2005
- Aggregators Should Continue to Play a Role In Delivering The Program
- Maintain Payment for Nominated Load at Current Levels
- Program Load Should Be Reported in Terms of Load Actually Nominated
- Streamline the Settlement Process

Create Organizational Stability Well In Advance Of Summer 2005

Given the importance of uncertainty in discouraging participation and making program marketing more difficult for aggregators, we recommend that no changes be made to the program before the next program year. Instead, the focus should be on creating organizational and program stability in a time frame that allows marketing well in advance of the summer 2005 season. This will provide a better indication of the level of interest in the program as currently designed. If response proves to be less than expected or there is a decision to build more capability for this program, it may be appropriate to change other program features to encourage greater participation. For now, however, stability is the highest priority.

Aggregators Should Continue To Play A Role In Delivering The Program

Third party aggregators serve a valuable function in marketing the program, assuring customers of a range of options, and providing technical assistance. They should continue to play a key role in the program even if the role of utilities in managing and dispatching the program increases.

Maintain Payment For Nominated Load At Current Levels

Payment for nominated load should remain at current levels, both to provide continuity and because participants place a high value on the availability of the capacity payment. Other program requirements (e.g., notification, higher compliance required, less control over curtailment length) are difficult for some participants, but there is evidence of ample interest under existing terms if there is stability in the program and the incentive.

As with other program requirements, there may be a case for changing the notification time frame and the criteria for compliance if more customers need to be attracted to the program. In the meantime, however, aggregators should be given the opportunity to see how much they can do with the existing program within a stable organizational and contractual framework.

Program Load Should Be Reported In Terms Of Load Actually Nominated

Utilities should report the amount of program capacity nominated. Monthly nominations plus the peak daily nomination, taken together, represent a better indication of the magnitude of the DRP program as a resource than does the registered capacity currently reported.

Streamline The Settlement Process

Settlement delays may be due to the many players involved, but the process needs to be streamlined so that aggregators and customers can be assured of receiving their payment within 60 days after the end of the month.

3.4 LESSONS LEARNED FROM NON-CALIFORNIA DR PROGRAMS

The experience of others with demand response programs may provide useful insights to programs in California, and so help maximize California programs' impact and cost-effectiveness. Toward that end, a task was commissioned to conduct a review of DR programs around the United States. The research team developed an extensive amount of data by building upon previous compilations of program features. Program veterans' insights on the history and future evolution of DR programs were obtained through personal interviews conducted via telephone. The full results of this effort are reported in Chapter 11 of the report. This section summarizes select findings, although the reader is encouraged to seek more detail in Chapter 11 as that chapter is already a pretty tight summary of the findings across a variety of programs.

Some of the findings from this research include:

Develop an "Honest" Value Proposition for the DR Program -- It was found that customers will work with utilities as long as utilities are viewed as working to solve resource problems and needs, and are not implementing a program to enhance profits.

High Electricity Prices are an Advantage in That They Encourage Program Participation But they also Pose Challenges Leading to Customer Dissatisfaction -- Ironically, high prices are seen as a "strength" of programs because they get C&I customers' attention and so enable programs to succeed because there is a crisis to overcome. At the same time, high prices are a major source of dissatisfaction for customers, leaving the DR industry "between a rock and a hard place" where mitigating prices means lower program participation, yet higher prices that spur program participation also bring heightened customer concerns about maintaining their competitiveness or meeting institutional budget constraints.

Technical Assistance Seen as Important for "Good" DR Programs -- Good programs have good technical assistance (the information side of technology). This includes energy audits, impact simulation software, rate analysis and the like. Case studies, customer readiness meetings (to exchange experiences and ideas) and venues for the exchange of ideas among customers were suggested.

Processes for Measuring Program Success with Information from Time Periods with Low Electricity Prices can be Misleading -- DR programs are specifically designed to mitigate prices during extreme or high-priced periods. Measurement of the success of a program in meeting these goals is best accomplished with data that reflect these infrequent, but relatively extreme events. The conventional measure of DR program success (i.e., MWs curtailed) suggests that successful programs have depended more on price volatility than program design. Comparing day-ahead bidding programs, for example, shows different levels of load participation, and this appears to be closely associated with prices being volatile (and high). Low prices and high reliability are closely associated with low DR program activity and, over time, participation.

Regular Field Testing of Programs is Important -- Testing maintains response capabilities and customers' attention and readiness. Programs that have survived most successfully have had relatively active customer relations, centering on communications and process testing, plus other readiness activities. These efforts appear to be increasingly on program mangers' minds, and again have been integral to successful programs' operations and customer satisfaction.

Timely and Continuing Customer Service and Program Support Important for Participation and Maintaining Program Viability -- Directly related to the testing issue is the effort to keep in touch with customers as needed to address not only DR-related matters but other energy service needs that may impinge on customers' interest and ability to participate in a DR program. This includes not only energy efficiency services and customer information services but also basic service configuration and reliability.

Financial Benefits to Customers should be Consistent with Supply Alternatives' Price and Risk Profiles -- Customers intuitively believe, and more programs are addressing, the need for DR pricing to be consistent with how supply alternatives are compensated. Given that DR (or any end-use) programs have inherent differences from supply alternatives it may or may not be possible, or desirable, to ensure such consistency. But progressive managers continue to seek ways to achieve compensation equitability, if not consistency, while at the same time having to keep administrative processes simple.

Integrated DR Program Design to Include Energy Efficiency Programs and Other Services can Produce Substantial Synergies -- One strategy for capturing a greater share of the value proposition involves integrating programs and services to address different aspects of that proposition. Reliability services ensure basic service, energy efficiency services and programs help keep bills lower, and DR programs help mitigate spot prices while providing a reserve capacity resource to address short-term reliability problems. Each area addresses different issues that customer's value. A number of program managers interviewed focused on this and some quotes from the interviews are informative in re-enforcing this view:

- "If you don't market demand response integrated with traditional energy efficiency you are missing an opportunity;"
- "The DR value proposition may be tough to make on its own."
- "Integrating EE and DR together makes customers more likely to participate."

4. 2004 CPP-DBP PROGRAM PARTICIPATION TRACKING AND ANALYSIS

This section summarizes program participation for the 2004 Critical Peak Pricing (CPP) and 2004 Demand Bidding Program (DBP), highlighting some of the trends that have occurred in participation since January 2004.

4.1 WG2 DR PROGRAM ELIGIBILITY

Exhibit 4-1 presents the total eligible population for the CPP and DBP programs across all three utilities in terms of number of accounts, the non-coincident peak demand, and the yearly energy usage. This exhibit also breaks down this eligible population into five size categories and distinct business types. While more than two-thirds of the eligible accounts are small (maximum annual demand less than 500 kW), they account for only slightly more than a quarter of the overall eligible non-coincident demand. On the other extreme only 5 percent of the eligible population are classified as Extra Large (maximum annual demand greater than 2 MW), however this population accounts for nearly 40 percent of the eligible non-coincident demand.

Exhibit 4-1
WG2 Eligible CPP and DBP Population

3 IOUs	Eligible Accounts	Eligible Accounts MW Sum**	Eligible Account GWh Sum	Eligible for CPP	Eligible for DBP
Size					
Very Small (100-200 kW) - SDG&E Only	2,080	297	900	1,993	2,079
Small (200-500 kW)	11,528	3,686	12,407	11,493	11,505
Medium (500-1000 kW)	3,962	2,736	9,763	3,757	3,956
Large (1000-2000 kW)	1,469	2,004	7,334	1,277	1,466
Extra Large (2000+ kW)	963	5,348	13,392	798	963
Business Type					
Commercial and TCU					
Office	3,324	2,125	6,204	3,292	3,314
Retail/Grocery	2,224	967	3,975	2,219	2,223
Institutional	3,717	2,048	6,291	3,682	3,717
Other Commercial	2,815	1,707	6,341	2,761	2,814
Transportation/Communication/Utility	1,604	1,210	2,789	1,545	1,602
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	804	1,107	3,406	691	804
Mining, Metals, Stone, Glass, Concrete	645	712	2,875	541	645
Electronic, Machinery, Fabricated Metals	1,641	1,153	4,280	1,561	1,641
Other Industrial and Agriculture	2,547	2,101	6,872	2,373	2,546
Unclassified					
Unknown	686	942	764	653	671
Totals	20,002	14,072	43,797	19,318	19,969

Similar Exhibits displaying the breakdown of eligible account for each utility are provided in Exhibits 4-2 through 4-4.

Exhibit 4-2
WG2 Eligible CPP and DBP Population for PG&E

PG&E	Eligible Accounts	Eligible Account MW Sum	Eligible Account GWh Sum	Eligible for CPP*	Eligible for DBP**
Size					
Small (200-500 kW)	3,829	1,289	4,592	3,827	3,824
Medium (500-1000 kW)	1,691	1,176	4,164	1,674	1,691
Large (1000-2000 kW)	724	999	3,426	688	724
Extra Large (2000+ kW)	591	3,583	6,600	536	591
Business Type					
Commercial and TCU					
Office	1,394	1,310	3,453	1,388	1,394
Retail/Grocery	743	417	1,504	743	743
Institutional	829	589	1,546	824	829
Other Commercial	1,039	892	3,334	1,034	1,039
Transportation/Communication/Utility	226	403	466	225	226
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	265	647	1,585	239	265
Mining, Metals, Stone, Glass, Concrete	244	231	814	231	244
Electronic, Machinery, Fabricated Metals	527	499	1,741	522	527
Other Industrial and Agriculture	1,132	1,238	3,781	1,083	1,132
Unclassified					
Unknown	444	821	557	436	439
Totals	6,843	7,047	18,781	6,725	6,838

Exhibit 4-3
WG2 Eligible CPP and DBP Population for SCE

SCE	Eligible Accounts	Eligible Account MW Sum	Eligible Account GWh Sum	Eligible for CPP*	Eligible for DBP**
Size					
Small (200-500 kW)	6,345	1,994	6,581	6,320	6,339
Medium (500-1000 kW)	1,896	1,297	4,705	1,719	1,895
Large (1000-2000 kW)	635	857	3,398	486	635
Extra Large (2000+ kW)	314	1,550	6,126	207	314
Business Type					
Commercial and TCU					
Office	1,155	561	1,973	1,142	1,155
Retail/Grocery	989	434	1,980	984	989
Institutional	1,952	1,155	3,902	1,931	1,952
Other Commercial	1,060	587	2,148	1,032	1,059
Transportation/Communication/Utility	1,093	692	1,964	1,071	1,091
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	456	434	1,723	372	456
Mining, Metals, Stone, Glass, Concrete	374	473	2,032	283	374
Electronic, Machinery, Fabricated Metals	853	534	2,048	784	853
Other Industrial and Agriculture	1,194	782	2,863	1,079	1,194
Unclassified					
Unknown	61	48	176	54	60
Totals	9,187	5,698	20,809	8,732	9,183

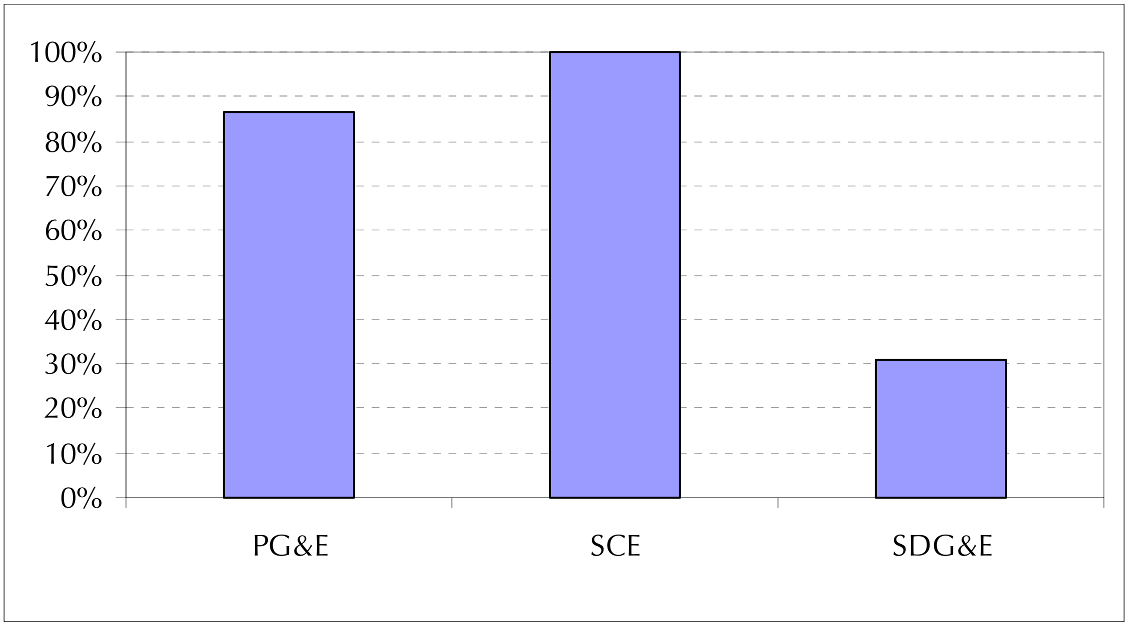
Exhibit 4-4
WG2 Eligible CPP and DBP Population for SDG&E

SDG&E	Eligible Accounts	Eligible Account MW Sum	Eligible Account GWh Sum	Eligible for CPP*	Eligible for DBP**
Size					
Very Small (100-200 kW)	2,080	297	900	1,993	2,079
Small (200-500 kW)	1,354	403	1,234	1,346	1,342
Medium (500-1000 kW)	375	263	895	364	370
Large (1000-2000 kW)	110	148	511	103	107
Extra Large (2000+ kW)	58	215	666	55	58
Business Type					
Commercial and TCU					
Office	775	253	777	762	765
Retail/Grocery	492	116	491	492	491
Institutional	936	304	843	927	936
Other Commercial	716	228	859	695	716
Transportation/Communication/Utility	285	116	358	249	285
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	83	26	97	80	83
Mining, Metals, Stone, Glass, Concrete	27	9	30	27	27
Electronic, Machinery, Fabricated Metals	261	120	491	255	261
Other Industrial and Agriculture	221	81	228	211	220
Unclassified					
Unknown	181	73	31	163	172
Totals	3,977	1,326	4,207	3,861	3,956

An important component of participation in the CPP or DBP programs is the presence of an interval meter at the customer site. Exhibit 4-5 shows the percentage of eligible accounts for each utility that are believed to have an interval meter. As the exhibit clearly shows, the three utilities vary greatly from one another. Currently, interval meters are present at 100 percent of eligible SCE accounts and 87 percent of eligible PG&E accounts, while only 31 percent of eligible SDG&E accounts have interval meters currently installed. This difference is to be expected since 52 percent of the eligible SDG&E population has an annual maximum demand less than 200 kW and thus is less likely to currently have an interval meter installed.[1]

[1] See Appendix J for a complete distribution of eligible accounts by size and business type for each utility.

Exhibit 4-5
Eligible CPP and DBP Population with Interval Meters Currently Installed
(Lower Percentage for SDG&E is Likely Attributable to Inclusion of
100 to 200 kW accounts in eligible population)



4.2 PROGRAM PARTICIPATION BY SEGMENT

Exhibit 4-6 summarizes overall program participation in the CPP and DBP programs across the three utilities broken down by customer size and business type. These figures were current as of mid-October 2004. Exhibits 4-7, 4-8, and 4-9 provide similar participation figures for PG&E, SCE and SDG&E individually. As the exhibits clearly show, participation to date varies widely across both utilities and programs. Across all three utilities participation for CPP totaled 206 accounts (103 of which were unique customers). Of these 206 CPP accounts, approximately 71 percent are PG&E customers, 25 percent are SDG&E customers and only 5 percent are SCE customers. For DBP there are a total of 763 accounts signed up across all three utilities (representing 481 unique customers). These DBP participants are distributed across the three utilities in the following manner; 14 percent are PG&E customers; 80 percent are SCE customers; and 6 percent are SDG&E customers.

Exhibit 4-6
CPP and DBP Program Participation to Date[2] Across All Utilities

3 IOUs	Participants	Participant Account MW Sum*	Participant Account GWh Sum	CPP Participants	DBP Participants
Size					
Very Small (100-200 kW) - SDG&E Only	11	2	3	7	6
Small (200-500 kW)	372	112	503	67	306
Medium (500-1000 kW)	292	207	782	79	220
Large (1000-2000 kW)	160	220	868	40	126
Extra Large (2000+ kW)	107	581	2,736	13	97
Business Type					
Commercial and TCU					
Office	60	54	199	11	52
Retail/Grocery	170	66	360	3	167
Institutional	98	141	547	36	63
Other Commercial	127	128	513	28	105
Transportation/Communication/Utility	100	63	209	28	72
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	64	100	436	7	57
Mining, Metals, Stone, Glass, Concrete	53	169	917	4	50
Electronic, Machinery, Fabricated Metals	101	171	868	32	74
Other Industrial and Agriculture	105	180	741	30	78
Unclassified					
Unknown	72	49	102	27	45
Total Accounts	950	1,122	4,891	206	763
Unique Customers	567			103	481

*Diversified customer peak demand

Exhibit 4-7
PG&E CPP and DBP Program Participation to Date

PG&E	Participants	Participant Account MW Sum	Participant Account kWh Sum	CPP Participants	DBP Participants
Size					
Small (200-500 kW)	66	18	62	54	12
Medium (500-1000 kW)	77	56	218	54	29
Large (1000-2000 kW)	53	74	302	28	30
Extra Large (2000+ kW)	39	193	856	10	30
Business Type					
Commercial and TCU					
Office	17	15	62	11	9
Retail/Grocery	4	4	22	2	2
Institutional	35	29	91	31	4
Other Commercial	25	29	128	10	16
Transportation/Communication/Utility	8	8	25	8	0
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	27	57	241	6	21
Mining, Metals, Stone, Glass, Concrete	13	28	106	3	11
Electronic, Machinery, Fabricated Metals	37	51	283	29	12
Other Industrial and Agriculture	51	120	477	28	26
Unclassified					
Unknown	26	1	3	18	8
Total Accounts	243	341	1,438	146	109
Unique Customers	127			68	70

[2] Data through end of October all utilities.

Exhibit 4-8
SCE CPP and DBP Program Participation to Date

SCE	Participants	Participant Account MW Sum	Participant Account kWh Sum	CPP Participants	DBP Participants
Size					
Small (200-500 kW)	289	87	425	3	286
Medium (500-1000 kW)	178	126	477	4	174
Large (1000-2000 kW)	89	122	495	1	88
Extra Large (2000+ kW)	59	350	1,692	0	59
Business Type					
Commercial and TCU					
Office	34	31	103	0	34
Retail/Grocery	165	62	334	1	164
Institutional	55	101	395	0	55
Other Commercial	79	77	295	0	79
Transportation/Communication/Utility	72	41	145	2	70
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	36	43	195	1	35
Mining, Metals, Stone, Glass, Concrete	40	141	810	1	39
Electronic, Machinery, Fabricated Metals	56	106	447	1	55
Other Industrial and Agriculture	54	60	264	2	52
Unclassified					
Unknown	24	25	99	0	24
Total Accounts	615	686	3,088	8	607
Unique Customers	395			7	388

Exhibit 4-9
SDG&E CPP and DBP Program Participation to Date

SDG&E	Participants	Participant Account MW Sum	Participant Account GWh Sum	CPP Participants	DBP Participants
Size					
Very Small (100-200 kW)	11	2	3	7	6
Small (200-500 kW)	17	6	17	10	8
Medium (500-1000 kW)	37	25	87	21	17
Large (1000-2000 kW)	18	25	71	11	8
Extra Large (2000+ kW)	9	37	188	3	8
Business Type					
Commercial and TCU					
Office	9	9	33	0	9
Retail/Grocery	1	1	4	0	1
Institutional	8	11	61	5	4
Other Commercial	23	23	90	18	10
Transportation/Communication/Utility	20	14	38	18	2
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	1	0	0	0	1
Mining, Metals, Stone, Glass, Concrete	0	0	0	0	0
Electronic, Machinery, Fabricated Metals	8	15	139	2	7
Other Industrial and Agriculture	0	0	0	0	0
Unclassified					
Unknown	22	23	1	9	13
Total Accounts	92	95	366	52	47
Unique Customers	45			28	23

These participation figures have grown substantially since the commencement of this evaluation. As of the Phase 1 Research Report (published in early April) there were only 57 accounts signed up for CPP and 420 signed up for DBP. As seen in the exhibits, SCE continues to account for the majority of the DBP participants, but this figure is now down to approximately 80 percent (versus 90 percent as of the Phase 1 Report). Additionally, as of the Phase 1 Report, SCE had zero signups for the CPP program. Since that time they have enrolled 8 accounts in CPP, however, they have not had any new signups since June 22nd. Initially, it was believed that SCE had no signups since few customers would benefit from CPP due to an inconsistency between CPP and the otherwise applicable tariff. However, signups have continued to be minimal even after this correction was made (late December 2003) and the information presumably had time to be disseminated. PG&E has seen rapid growth in their signups for both the CPP and the DBP programs. Exhibit 4-7 above contains accounts that had signed up and were considered effective as of October 28th, however there were an additional 63 CPP and 233 DBP accounts that had signed up as of October 28th but were not yet effective in the program. SDG&E also has 5 DBP and 10 CPP participants that have signed up but were not yet effective as of the end of October. Exhibits 4-10 and 4-11 show the rise in participation in the CPP and DBP programs at each of three utilities over the course of the summer.

Exhibit 4-10
CPP Program Participation Over Time by Utility

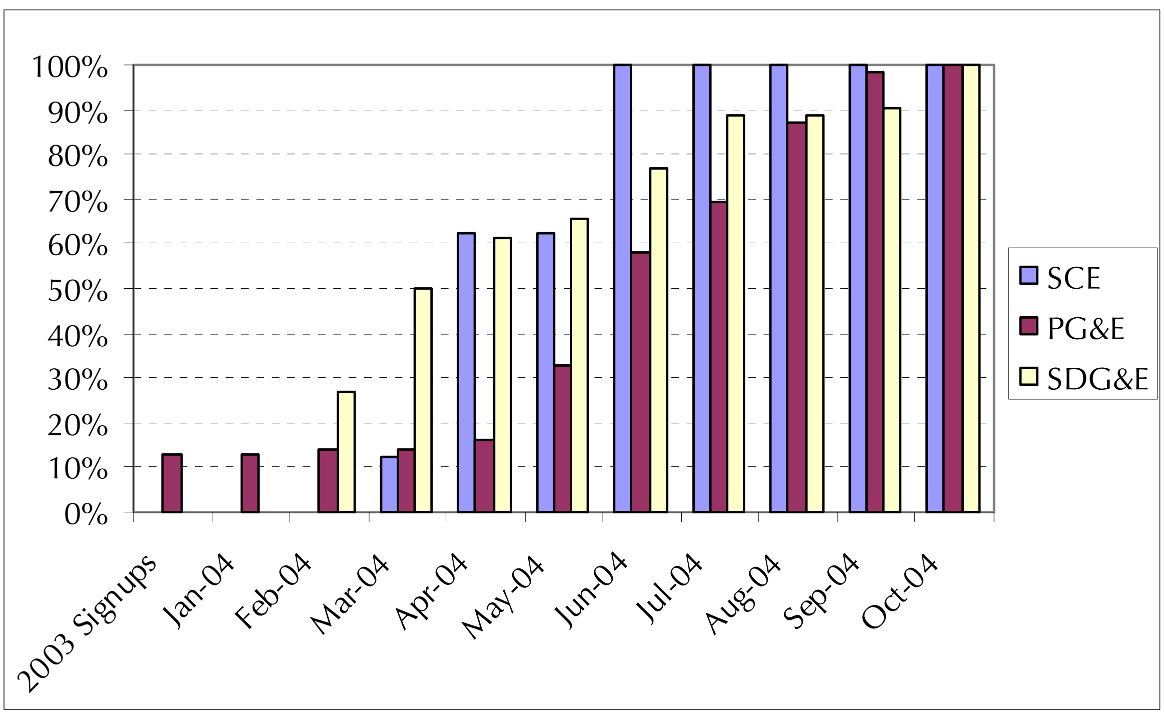
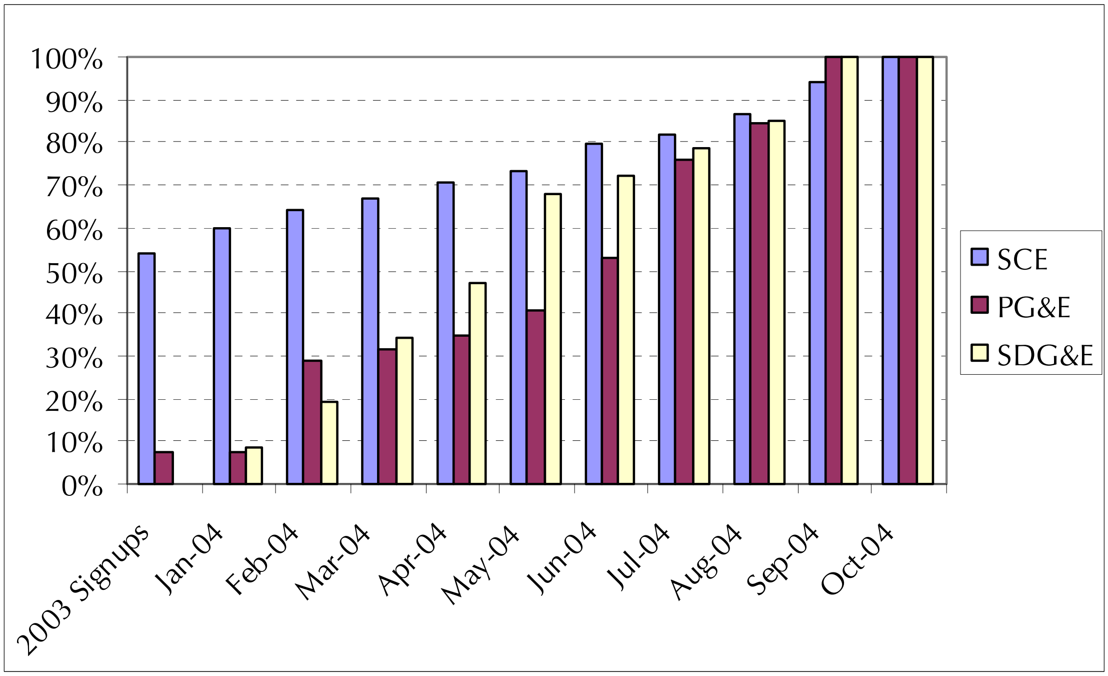


Exhibit 4-11
DBP Program Participation Over Time by Utility



The distribution of participants by business type – aggregated into three main sectors (Industrial, Commercial and Institutional) - varies significantly among the utilities and between CPP and DBP, as is evident in Exhibits 4-12 and 4-13. Exhibit 4-12 shows the distribution of the CPP participants across the three business type sectors for each of the utilities and illustrates the similarity in the distributions of CPP participants for PG&E and SCE.[3] At both of these utilities, Industrial customers make up the majority of the participants followed by Institutional and then Commercial customers. For SDG&E the majority of the CPP participants are Institutional customers (primarily water pumping facilities), followed by Commercial customers. Industrial customers make up only 5 percent of their total participants.

The distribution of DBP participants across the three business type sectors for each of the utilities is provided in Exhibit 4-13. For DBP the distribution of participants is similar in the SDG&E and SCE territories with Commercial customers making up the majority of participants followed by Industrial and then Institutional customers. In the PG&E territory, nearly 70 percent of the DBP participants are Industrial customers, a quarter are Commercial, and only 5 percent are Institutional. It is interesting to note that, in general, Institutional customers seem to favor the CPP program with its peak period pricing over the DBP program that requires customers to place load reduction bids.

[3] The distribution of SCE CPP participants is based on a small sample of only 8 accounts and thus should not be thought of as representative of future potential for this program.

Exhibit 4-12
CPP Participation by Business Type Sector - All Utilities

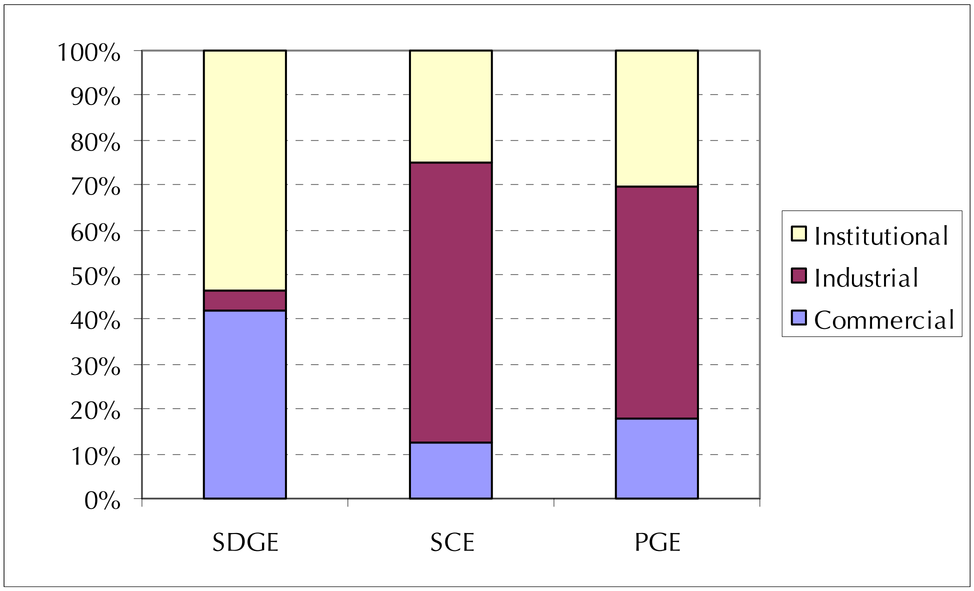
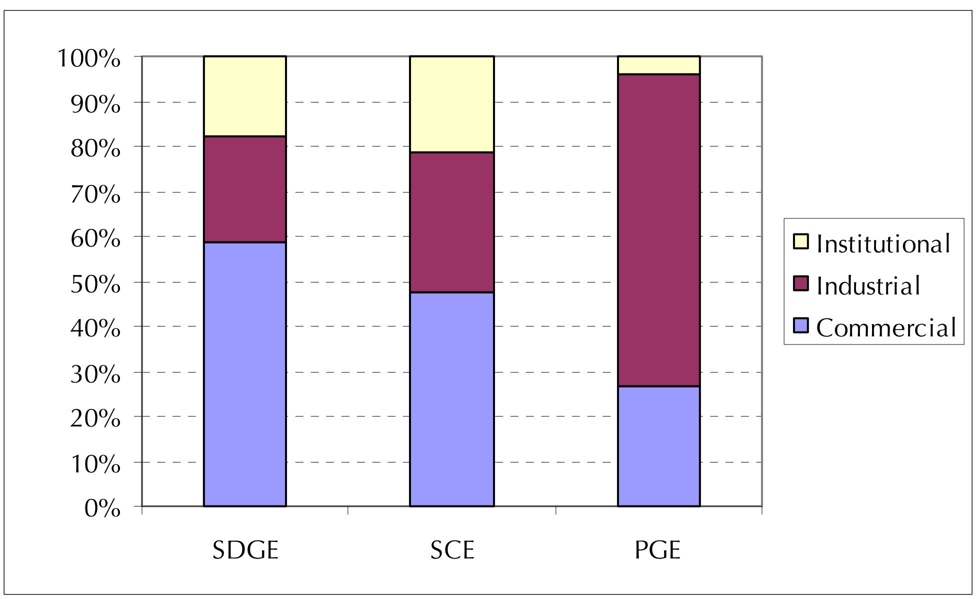


Exhibit 4-13
DBP Participation by Business Type Sector - All Utilities



Exhibits 4-14 and 4-15 show the distribution of CPP and DBP program participants across the five main size categories. One difference illustrated by these two exhibits is that the largest customers (those with maximum demands greater than 2 MW) seem to favor the DBP program over the CPP program at each of the three utilities.

Exhibit 4-14
CPP Program Participation by Business Size - All Utilities

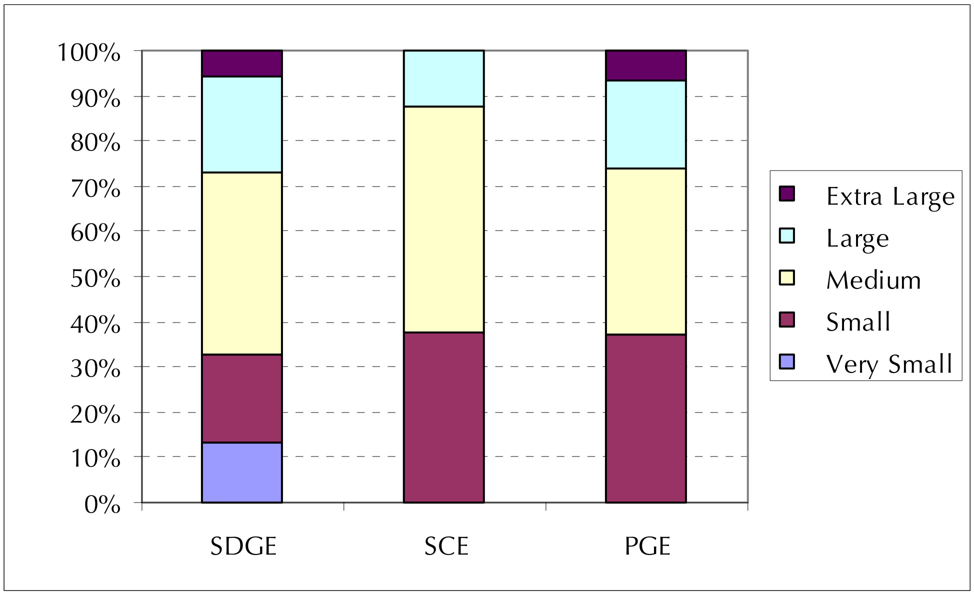
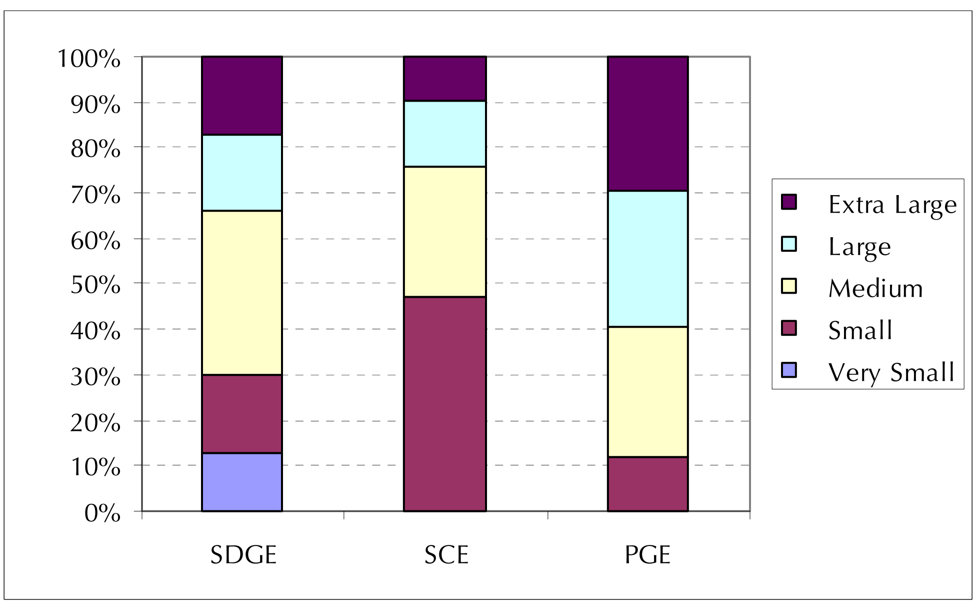


Exhibit 4-15
DBP Program Participation by Business Size - All Utilities



4.3 PROGRAM PENETRATION LEVELS

Information on eligible participants combined with the actual program participation figures indicate which customer groups have been drawn towards signing for the CPP and DBP programs. Exhibit 4-16 presents the degree to which the overall eligible population, the non-coincident maximum demand, and the yearly energy usage have been penetrated by the 2004 DR programs across all three of the utilities. Further breakdowns by customer business type and size, as well as specific penetration rates into the CPP and DBP eligible populations are also provided.

As is evident in the Exhibit 4-16, overall program penetration levels tend to be much lower in the Small and Very Small sized businesses (overall participant penetration levels range from a low of 0.5 percent for Very Small customers to a high of 11 percent for Extra Large customers). Program penetration levels also tend to be lower in Commercial and Institutional facilities and higher in Industrial facilities. The rate of participant penetration for business types ranges from 1.8 percent for Office type businesses to 8.2 percent for Mining, Metals, Stone, Glass and Concrete businesses. The "Unknown" category shows a penetration rate of 10.5 percent, however, the majority of customers in this category are classified as unknown because they are new program participants that were not included in the original population frame[4].

Exhibit 4-16 also provides a side-by-side comparison of the percent of eligible customers that have signed up for CPP versus DBP in each of the size categories. The DBP program has a very high rate of program participation in the Large and Extra Large categories (8.6 and 10.1 percent respectively), while CPP saw the highest degree of participation in the Large and Medium categories (3.1 and 2.1 percent respectively).

Penetration levels for each of the individual utilities are presented in Exhibits 4-17 through 4-19. An important item to note here is that SCE signed up a chain of small grocery store outlets for their DBP program that amount to 20 percent of their total DBP participants. As a result, the DBP penetration rate for the Retail/Grocery sector is shown in Exhibit 4-19 to be 16.6 percent. In interviews conducted for this evaluation, this chain indicated it would not be able to meet the 100 kW bid minimum required for individual sites. With the small grocery store outlets removed, the penetration rate percentage for the Retail/Grocery sectors falls to approximately 6 percent.

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[4] The business type classifications were determined based on the SIC or NAICS code from the original population frame and thus new program participants missing from the frame were often categorized as unknown.

Exhibit 4-16
WG2 DR Program Penetration Across All Utilities[5]

3 IOUs	Participant Penetration	Participant MW Penetration*	Participant GWh Penetration*	CPP Penetration	DBP Penetration
Size					
Very Small (100-200 kW) - SDG&E Only	0.5%	0.6%	0.3%	0.4%	0.3%
Small (200-500 kW)	3.2%	3.0%	4.1%	0.6%	2.7%
Medium (500-1000 kW)	7.4%	7.6%	8.0%	2.1%	5.6%
Large (1000-2000 kW)	10.9%	11.0%	11.8%	3.1%	8.6%
Extra Large (2000+ kW)	11.1%	10.9%	20.4%	1.6%	10.1%
Business Type					
Commercial and TCU					
Office	1.8%	2.6%	3.2%	0.3%	1.6%
Retail/Grocery	7.6%	6.8%	9.0%	0.1%	7.5%
Institutional	2.6%	6.9%	8.7%	1.0%	1.7%
Other Commercial	4.5%	7.5%	8.1%	1.0%	3.7%
Transportation/Communication/Utility	6.2%	5.2%	7.5%	1.8%	4.5%
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	8.0%	9.1%	12.8%	1.0%	7.1%
Mining, Metals, Stone, Glass, Concrete	8.2%	23.7%	31.9%	0.7%	7.8%
Electronic, Machinery, Fabricated Metals	6.2%	14.8%	20.3%	2.0%	4.5%
Other Industrial and Agriculture	4.1%	8.5%	10.8%	1.3%	3.1%
Unclassified					
Unknown	10.5%	5.2%	13.4%	4.1%	6.7%
Total Accounts	4.7%	8.0%	11.2%	1.1%	3.8%

*Diversified customer peak demand

Exhibit 4-17
PG&E CPP and DBP Program Penetration Levels

PG&E	Participant Penetration	Participant MW Penetration*	Participant GWh Penetration*	CPP Penetration	DBP Penetration
Size					
Small (200-500 kW)	1.7%	1.4%	1.3%	1.4%	0.3%
Medium (500-1000 kW)	4.6%	4.7%	5.2%	3.2%	1.7%
Large (1000-2000 kW)	7.3%	7.4%	8.8%	4.1%	4.1%
Extra Large (2000+ kW)	6.6%	5.4%	13.0%	1.9%	5.1%
Business Type					
Commercial and TCU					
Office	1.2%	1.2%	1.8%	0.8%	0.6%
Retail/Grocery	0.5%	0.9%	1.4%	0.3%	0.3%
Institutional	4.2%	4.9%	5.9%	3.8%	0.5%
Other Commercial	2.4%	3.2%	3.8%	1.0%	1.5%
Transportation/Communication/Utility	3.5%	2.1%	5.4%	3.6%	0.0%
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	10.2%	8.8%	15.2%	2.5%	7.9%
Mining, Metals, Stone, Glass, Concrete	5.3%	12.0%	13.1%	1.3%	4.5%
Electronic, Machinery, Fabricated Metals	7.0%	10.2%	16.2%	5.6%	2.3%
Other Industrial and Agriculture	4.5%	9.7%	12.6%	2.6%	2.3%
Unclassified					
Unknown	5.9%	0.2%	0.5%	4.1%	1.8%
Total Accounts	3.6%	4.8%	7.7%	2.2%	1.6%

*Diversified customer peak demand

[5] DBP Penetration in the Retail/Grocery business type is significantly skewed by a series of SCE program signups. See Exhibit 4-18 and surrounding text for further explanation.

Exhibit 4-18
SCE CPP and DBP Program Penetration Levels

SCE	Participant Penetration	Participant MW Penetration*	Participant GWh Penetration*	CPP Penetration	DBP Penetration
Size					
Small (200-500 kW)	4.6%	4.4%	6.5%	0.0%	4.5%
Medium (500-1000 kW)	9.4%	9.7%	10.1%	0.2%	9.2%
Large (1000-2000 kW)	14.0%	14.2%	14.6%	0.2%	13.9%
Extra Large (2000+ kW)	18.8%	22.6%	27.6%	0.0%	18.8%
Business Type					
Commercial and TCU					
Office	2.9%	5.5%	5.2%	0.0%	2.9%
Retail/Grocery	16.7%	14.2%	16.9%	0.1%	16.6%
Institutional	2.8%	8.7%	10.1%	0.0%	2.8%
Other Commercial	7.5%	13.1%	13.7%	0.0%	7.5%
Transportation/Communication/Utility	6.6%	5.9%	7.4%	0.2%	6.4%
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	7.9%	10.0%	11.3%	0.3%	7.7%
Mining, Metals, Stone, Glass, Concrete	10.7%	29.9%	39.9%	0.4%	10.4%
Electronic, Machinery, Fabricated Metals	6.6%	19.8%	21.8%	0.1%	6.4%
Other Industrial and Agriculture	4.5%	7.6%	9.2%	0.2%	4.4%
Unclassified					
Unknown	39.3%	52.4%	56.3%	0.0%	40.0%
Total Accounts	6.7%	12.0%	14.8%	0.1%	6.6%

*Diversified customer peak demand

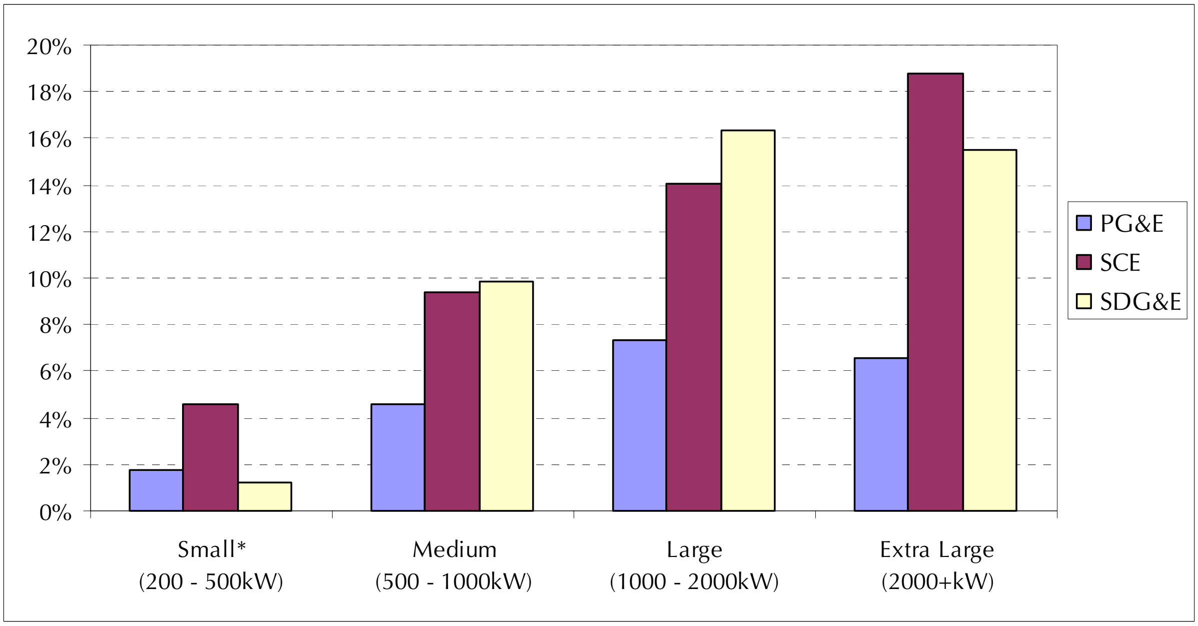
Exhibit 4-19
SDG&E CPP and DBP Program Penetration Levels

SDG&E	Participant Penetration	Participant MW Penetration*	Participant GWh Penetration*	CPP Penetration	DBP Penetration
Size					
Very Small (100-200 kW) - SDG&E Only	0.5%	0.6%	0.3%	0.4%	0.3%
Small (200-500 kW)	1.3%	1.6%	1.4%	0.7%	0.6%
Medium (500-1000 kW)	9.9%	9.7%	9.8%	5.8%	4.6%
Large (1000-2000 kW)	16.4%	16.6%	13.9%	10.7%	7.5%
Extra Large (2000+ kW)	15.5%	17.3%	28.2%	5.5%	13.8%
Business Type					
Commercial and TCU					
Office	1.2%	3.4%	4.2%	0.0%	1.2%
Retail/Grocery	0.2%	0.5%	0.7%	0.0%	0.2%
Institutional	0.9%	3.7%	7.2%	0.5%	0.4%
Other Commercial	3.2%	10.1%	10.5%	2.6%	1.4%
Transportation/Communication/Utility	7.0%	12.4%	10.7%	7.2%	0.7%
Industrial and Agricultural					
Petroleum, Plastic, Rubber and Chemicals	1.2%	0.6%	0.2%	0.0%	1.2%
Mining, Metals, Stone, Glass, Concrete	0.0%	0.0%	0.0%	0.0%	0.0%
Electronic, Machinery, Fabricated Metals	3.1%	12.3%	28.3%	0.8%	2.7%
Other Industrial and Agriculture	0.0%	0.0%	0.0%	0.0%	0.0%
Unclassified					
Unknown	12.2%	30.8%	1.8%	5.5%	7.6%
Total Accounts	2.3%	7.2%	8.7%	1.3%	1.2%

*Diversified customer peak demand

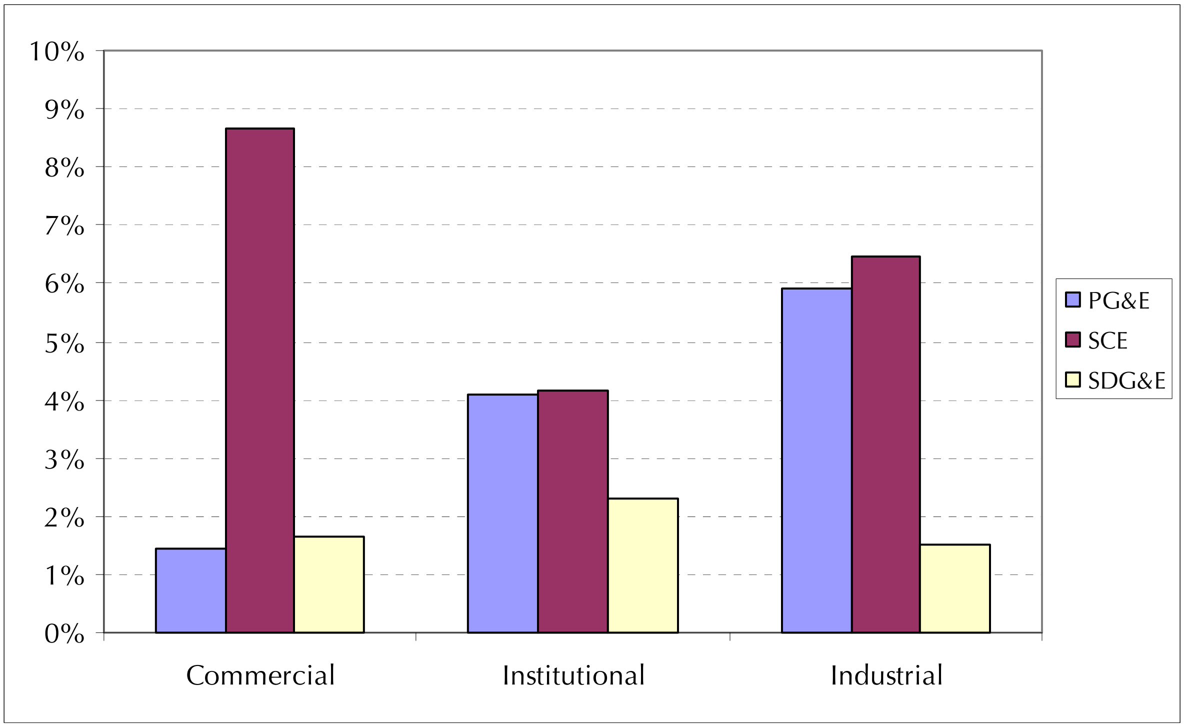
Exhibit 4-20 demonstrates a clear relationship between customer size and penetration rates. With only two exceptions, the penetration rate increased with each increase in the customer size category. For SCE and SDG&E, the penetration rates range from nearly five to more than seven times higher for Extra Large customers than for Small. For PG&E the relationship was not as strong, but is still evident.

Exhibit 4-20
Combined CPP-DBP Participant as a Percent of Eligible Population by Size and Utility
(* Small goes down to 100kW for SDG&E)



As mentioned earlier and seen in Exhibit 4-21, the large number of chain grocery stores that enrolled in the DR programs in the SCE territory clearly skews the Commercial results presented below. Excluding these customers from the analysis, the Commercial sector penetration rate for SCE falls from 8.7 percent to 5.6 percent. After the small grocery stores have been removed for SCE the exhibit below shows that for both PG&E and SCE the highest penetration rates are found in the Industrial sector, followed by the Institutional and finally the Commercial sector. For SDG&E, the penetration by segment is much closer with Institutional customers having only a slightly greater rate of program signup than Commercial and Industrial customers. Many of the participants signed up for the CPP program in SDG&E territory are water pumping facilities that have been classified as Institutional.

Exhibit 4-21
Combined CPP-DBP Participant Penetration by Business Type Sector and Utility



4.4 CPP AND DBP INCENTIVES

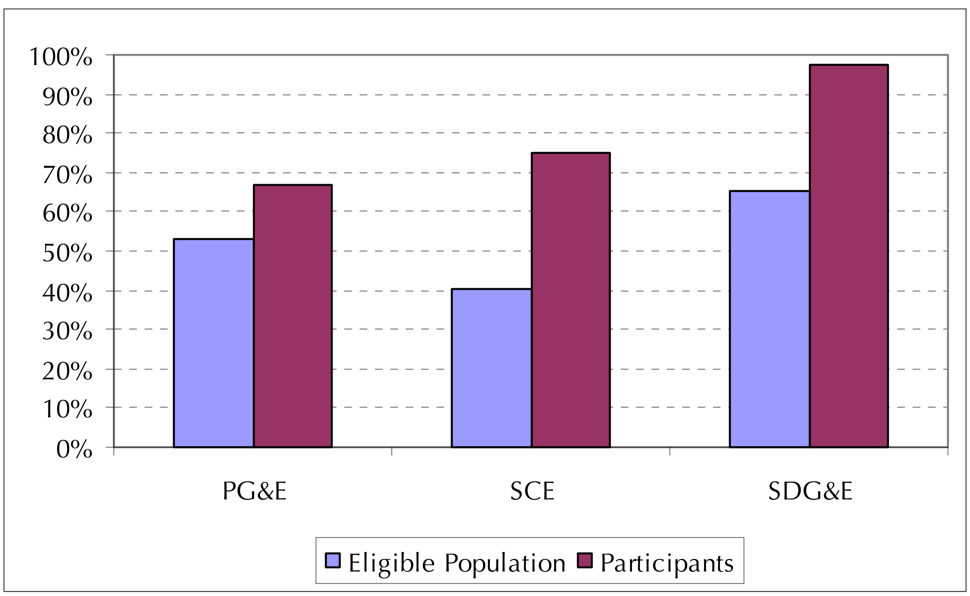
As of the end of the summer participation in the utilities Technical Assistance Incentive was extremely low. PG&E reported that only one CPP and two DBP customers had indicated interest in the incentive upon signing up for the DR programs, however, none of these customers had followed through and taken the actions required to receive the Technical Assistance. SCE and SDG&E also reported that none of their customers enrolled in the DR programs had taken advantage of this incentive.

Enrollment in the Bill Protection component of CPP was nearly 100 percent with all but five of PG&E's CPP customers and all but two of SDG&E and SCE's CPP customers signing up for Bill Protection upon enrollment in the CPP program. The idea behind the Bill Protection Incentive is that it allows customers to participate in CPP for one summer at no risk so that they can determine what kind of demand response actions are feasible for their facility. It ensures that a customer will not pay higher bills on the new CPP rate over what they would have paid on their previous rate. The Bill Protection incentive originally had a 3 percent performance requirement and a 12-month commitment included as part of the terms of the incentive, however, based on a ruling made during the summer of 2004, all customers enrolling in CPP can now sign up for Bill Protection without the 3 percent performance requirement. This gives customers the piece of mind that they can try the CPP rate for a year with no penalty if they are unable to reduce their load.

As presented in Chapter 2, the utilities conducted rate analyses on a large portion of the CPP eligible population to determine whether customers would pay more or less on the CPP tariff than on their otherwise applicable tariff (OAT). The analyses were based on energy usage in 2003 with load reduction scenarios generally ranging from 0 to 20 percent. Because the CPP rate is considered "Revenue Neutral", roughly half of the eligible CPP customers would receive lower bills on the CPP rate without making any changes to their current load patterns. The rate analyses for the actual 2004 CPP participant population showed that for SCE and SDG&E, all but one of the CPP participants benefited from the CPP rates without making any changes to their consumption pattern. For SCE the average savings of the CPP participants was approximately 1.1 percent versus 0.3 percent for the non-participant population. For SDG&E the average savings of the participants was 3.1 percent versus 0.4 percent for the non-participant population. For PG&E the average savings of the participants was 0.5 percent versus 0.03 percent for the non-participant population.

These customers who benefit without making any changes are sometimes referred to as "Structural Benefitters". Exhibit 4-22 compares the percentage of CPP eligible customers that are Structural Benefitters to the percentage of CPP participants that are Structural Benefitters.

Exhibit 4-22
CPP Structural Benefitters – Eligible Population Versus Participants



4.5 PARTICIPANT VERSUS NON-PARTICIPANT CHARACTERISTICS

This section attempts to determine the differences, if any, between participants and non-participants in the 2004 CPP or DBP programs, and how these differences may influence participation in the programs. The focus of this analysis is on factors believed to have a role in the decision to participate in one or more of the DR programs, as opposed to the general characteristics of the two groups that were discussed previously in this section.

During the course of this project, several surveys of CPP and DBP participants and non-participants were conducted. For participants, there were in-depth surveys in early 2004, post-event surveys in late summer, and the final evaluation survey in the fall. The latter two results are presented in Chapter 5 of this report (the original in-depth results were published in our March 2004 Phase I Report). Non-participants were included in the early in-depth surveying as well as a stand-alone quantitative non-participant survey that took place in March of 2004 and was published in early August 2004 (see Chapter 2 for summary of reports for this evaluation). In order to model differences across the two groups, this analysis looked at questions that were asked of both participants and non-participants during the course of this evaluation.

Exhibit 4-23 presents the distribution of the answers to the common survey questions broken out by participants and non-participants.

Exhibit 4-24 shows that there are indeed differences between the two groups. However, it is not clear from this table whether these differences are indicative of meaningful differences, or just the result of random variation (e.g., sampling variation).

One method that can be used to determine if these differences are meaningful is to test whether the difference in means for the variables is statistically significant. This is accomplished by comparing the difference in the average values for each question to the standard deviations of this question. If the difference is significantly different than the standard deviation for that question, then the difference is statistically significant and therefore may be indicative of a meaningful difference between the two groups. The test statistic is a t-statistic and a value of 1.96 implies significance at the 95% level, and a value of 1.64 implies that it is significant at a 90 percent level. This analysis is presented in Exhibit 4-25.

Exhibit 4-23
Survey Responses by Participation Group

Variable	Frequency by participant group	
	Non-participants	Participants
What percent of firms total operating cost is energy costs (EC5)		
Less than 1%	11 (3%)	1 (1%)
1 – 4 percent	75 (23%)	20 (21%)
5 to 10 percent	100 (30%)	29 (31%)
11 to 25 percent	82 (35%)	30 (32%)
Over 25 percent	62 (19%)	15 (16%)
Which is the *largest* end use of electricity for this facility (EC9A)		
Lighting	24 (7%)	5 (5%)
HVAC	91 (27%)	30 (32%)
Continuous processing	122 (37%)	28 (30%)
Batch processing	13 (4%)	8 (8%)
Refrigeration	32 (10%)	12 (13%)
Which is the *second largest* end use of electricity for this facility (EC9A)		
Lighting	138 (42%)	46 (48%)
HVAC	64 (19%)	12 (13%)
Continuous processing	28 (8%)	10 (11%)
Batch processing	34 (10%)	13 (14%)
Refrigeration	24 (7%)	5 (5%)
How closely does firm monitor electricity markets and prices (EM3)		
Very closely	70 (21%)	33 (35%)
Somewhat closely	112 (34%)	40 (42%)
Not very closely	148 (45%)	22 (23%)
How likely is it that CA power supplies will be inadequate in the future (EM5)	74 (22%)	16 (17%)
Very likely	145 (44%)	39 (41%)
Somewhat likely	92 (28%)	27 (28%)
Somewhat unlikely	19 (6%)	13 (14%)
Very unlikely		
How concerned is firm about energy prices relative to other costs (EM7)		
Very concerned	231 (70%)	68 (72%)
Somewhat concerned	84 (25%)	24 (25%)
Relatively unconcerned	15 (5%)	3 (3%)

Exhibit 4-24
Survey Responses by Participation Group (continued)

Variable	Frequency by participant group	
	Non-participants	Participants
Significance of effect on **occupant comfort** as a concern in DR program participation (ES13A)		
Insignificant (1)	66 (20%)	18 (19%)
2	48 (15%)	14 (15%)
3	65 (20%)	25 (26%)
4	44 (13%)	14 (15%)
Significant (5)	107 (32%)	24 (25%)
Significance of effect on **products or productivity** as a concern in DR program participation (ES13B)		
Insignificant (1)	28 (8%)	10 (11%)
2	19 (6%)	2 (2%)
3	36 (11%)	13 (14%)
4	47 (14%)	17 (18%)
Significant (5)	200 (61%)	53 (56%)
Significance of effect on **potential bill savings** as a concern in DR program participation (ES13C)		
Insignificant (1)	34 (10%)	6 (6%)
2	21 (6%)	12 (13%)
3	71 (22%)	15 (16%)
4	62 (19%)	23 (24%)
Significant (5)	142 (43%)	39 (41%)
Significance of **inability to reduce peak load** as a concern in DR program participation (ES13a)		
Insignificant (1)	27 (8%)	12 (13%)
2	30 (9%)	6 (6%)
3	61 (18%)	26 (27%)
4	68 (21%)	24 (25%)
Significant (5)	144 (44%)	27 (28%)

Exhibit 4-25
Test of Significance of Differences between Participants and Non-participants

Variable	Means by Group		T-value of difference
	Non -participants	**Participants**	
What percent of firms total operating cost is energy costs (EC5)	3.33	3.4	0.57
Which is the *largest* end use of electricity for this facility (EC9A)			
Lighting			
HVAC	0.07	0.05	0.74
Continuous processing	0.28	0.32	0.74
Batch processing	0.37	0.29	1.39
Refrigeration	0.04	0.08	1.78**
	0.10	0.13	0.77
Which is the *second largest* end use of electricity for this facility (EC9A)			
Lighting	0.42	0.48	1.13
HVAC	0.19	0.12	1.52
Continuous processing	0.08	0.10	0.58
Batch processing	0.10	0.13	0.86
Refrigeration	0.07	0.05	0.74
How closely does firm monitor electricity markets and prices (EM3)	2.24	1.89	3.97*
How likely is it that CA power supplies will be inadequate in the future (EM5)	2.17	2.38	2.08*
How concerned is firm about energy prices relative to other costs (EM7)	1.34	1.31	0.47
Significance of effect on **occupant comfort** as a concern in DR program participation (ES13A)	3.23	3.13	0.65
Significance of effect on **products or productivity** as a concern in DR program participation (ES13B)	4.13	4.06	0.42
Significance of effect on **potential bill savings** as a concern in DR program participation (ES13C)	3.77	3.81	0.21
Significance of **inability to reduce peak load** as a concern in DR program participation (ES13a)	3.82	3.50	2.09*

*Denotes that the difference between the two groups is significant at the 95% confidence level.
**Denotes difference that the difference is significant at the 90% level of confidence.

The data in Exhibit 4-25 indicates that there are some statistically significant differences between the characteristics and opinions of participants and non-participants. These differences were the following:

- Non-participants were more likely to say that the inability to reduce peak demand is a significant factor in the decision to participate;
- Non-participants were also less likely to monitor and analyze electricity markets and prices; and,
- Non-participants were less likely to have batch processing as a large electric end-use category.

These results also show that participants are more likely to believe that it is *very unlikely* that California's power supplies would be *inadequate* to meet future power demand. This implies that they believe it is likely that California's power supplies would be adequate to meet future demand. This surprising result may be due to the wording of the question (i.e., adequate may have been mistaken for the term inadequate by responders). These results run counter to several other recent utility studies that show that, when participants believe that it is likely that power supplies will be inadequate to meet future power demand; then, customers are more likely to work with utilities in seeking a solution to this resource problem. This includes higher rates of participation in DR programs. On the other hand, customers who follow California energy markets closely may have believed that resources were adequate based on information at the time of the non-participant survey (March 2004) while, by fall 2004, the time of the final participant survey, informed customers may have concluded the opposite because of warnings from California regulatory agencies promulgated in both the mass market and trade press.

While the analysis presented in Exhibit 4-25 provides some insights into the issue of participants versus non-participants, its scope is limited because it is a univariate analysis. That is, it does not control for the effect of other variables on the observed difference in that single variable. For example, it may be that more industrial customers are found in the participant group relative to the non-participant group, which may have a relatively larger share of commercial customers. It also may be true that lighting is a larger share of the energy consumption of commercial facilities. Therefore, a comparison of the share of energy used for lighting between the two groups will show that non-participants have a larger share. This may lead to the conclusion that firms with large lighting loads are less likely to participate in the program, when the true effect is that the non-participant group has a larger share of commercial buildings.

In order to overcome these issues, the univariate analysis must be extended to a multivariate analysis. For this evaluation, a logistic analysis was used to determine those variables which best differentiate between the two groups.[6] The logistic analysis is a regression technique in

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[6] Discriminate analysis is another method that can be used for this research. However, logistic analysis is generally preferred because it usually involves fewer violations of assumptions, is robust, handles categorical as well as continuous variables, and has coefficients that are easier to interpret. Logistic analysis is also preferred then the group sizes are very unequal (as in this case). We did conduct a discriminate analysis as well, and found that it produced the same general conclusions as the logistic analysis. Cluster analysis is not appropriate for this research

which the dependent variable takes on discrete values. In this case, the dependent variable is equal to 1 if the customer is a participant, and 0 if they are not. Like the more familiar linear regression analysis, a logistic analysis includes independent variables and it estimates coefficients on these independent variables, which relate the effect of changes in that variable with changes in the dependent variable, all other variables held fixed. Logistic analysis also produces t-values on these coefficients that indicate the statistical significance of these coefficients. Logistic analysis differs from linear regression in that the relative size of the coefficient does not necessarily indicate the relative importance of the variable because the model is inherently non-linear. Thus, the relative impact of one variable depends upon the value of all the other variables in the model. Exhibit 4-26 presents the results of the logistic analysis on the differences between participants and non-participants. In this analysis, the exhibit does not present the results for the control variables used to represent the utility, the size of the firm, and the business type.[7] The data included in Exhibit 4-26 combines participants in both DBP and CPP to generate adequate sample sizes for the analyses. As a result, the analysis focuses on the tendencies to participate in a 2004 DR program and does not focus on what factors may have resulted in a customer choosing CPP over DBP or vice versa.

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because cluster analysis is used to determine the best way in which firms can be classified into groups. This analysis however is concerned with finding those variables that can be used to differentiate the pre-determined groups (participants and non-participants).

[7] These control variables were used as proxies for a number of factors. The utility identifier variable (i.e., SCE, PG&E or SDG&E) could represent the intensity and/or the effect of that utility's marketing programs, variations in tariff designs, or simple the relationship between the utilities and these customer segments. Other control variables focused on size (in terms of peak demand), and customer segment (i.e., institutional, industrial and commercial). These variables are used a control for other factors that are omitted from this equation. However, a focused research effort of participation factors with a larger sample of participants could be conducted to explore the influence of these other variables, which may serve as a proxy for marketing intensity (one utility may market the program more intensively than another utility), and customer size (where larger customers may have more curtailment options).

Exhibit 4-26
Participation in DBP and CPP: Logistic Analysis Results

Variable	Coefficient (t-value)
Participated in other programs	1.75 (4.37)
Does not closely watch electricity markets and prices (EM3=1)	-0.93 (-3.43)
Closely watches electricity markets and prices (EM3 = 3)	0.58 (2.23)
Largest end use is batch processing (EC9A = 4)	0.96 (3.10)
Largest end use is continuous processing (EC9A = 3)	-0.67 (-2.51)
Very unlikely that California's power supply will be inadequate to meet expected demand (EM5=4)	0.91 (2.42)
Energy is over 10% of firms annual operating costs (EC5>=4)	0.45 (1.97)
The inability to reduce peak load is a significant concern about DR program participation (ES13D=5)	-0.74 (-3.08)
The potential peak bill savings is an *insignificant* concern about DR program participation (ES13C=1)	-1.22 (-2.44)
The potential peak bill savings is a *very significant* concern about DR program participation (ES13C=5)	-0.55 (-2.36)
McFadden's pseudo R-square	17%

Variables that have positive coefficients in the exhibit above are those variables that increase the tendency for a firm to participate in either CPP or DBP. Thus, the model shows that participants are more likely to:

- have participated in other DR programs,
- closely monitor electricity markets and prices,
- self-report having energy use over 10% of their total annual operating costs[8], and
- believe it is unlikely that California's power supply will be inadequate (confirming the finding in Exhibit 4-25).

[8] It is unlikely that any customer actually has energy costs that exceed 10% of total annual operating expenses with all labor and raw materials included. However, self-reports in surveys such as this one have shown similarly high values. One explanation might be that they are looking at a sub-set of operating costs that focus on the building, e.g., rent and maintenance.

These results indicate that participants are generally more aware of energy options. Also, participants are more likely to have batch processing as the largest end use, perhaps because they can easily reschedule production.

Exhibit 4-26 shows that non-participants are more likely to:

- perceive the inability to reduce peak demand as a larger barrier than participants to their decision to participate in one of the programs,

- have an extensive amount of continuous processing, which may reduce their ability to shift load, and

- believe that potential peak bill savings are either a very significant concern or a very insignificant concern for participation in demand response programs. These opposing viewpoints indicate that for some non-participants participation would not be an option at any price while for others the current bill savings are not worth the effort to participate.

The relatively low adjusted R-Square indicates that the model explains only a portion of the factors important in the participation decision. However, all variables with t-values greater than two are statistically significantly at a 95% level of confidence.

It is important to note that in the scope of the entire WG2 DR evaluation this was a limited research effort and thus a combination of more time and a targeted set of data focused on examining the participation decision, as well as a larger sample of participants could provide considerably more information on those factors that influence a decision to participate in DR programs.

Summary – Participant / Non-Participant Characteristics

This analysis shows some results that have been found in other studies and that support anecdotal evidence gathered from the surveys of program managers for both programs in California and programs outside California.[9] In particular, those customers that have a high electricity market "IQ", i.e., customers that understand and follow the market are more likely to participate in DR programs. They appreciate the fact that electricity prices can vary by 1,000 across hours in a year and, therefore, seem to be more willing to work with a utility or energy provider by participating in a DR program.

This also implies that customer education about electric markets would help increase participation in DR programs, and reduce barriers to participation.

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[9] See Chapter 11 for a review of non-California program managers' responses on the success factors for DR programs.

5. PARTICIPANT POST-EVENT AND FINAL EVALUATION SURVEY RESULTS

This section describes the Post-Event and Final Evaluation surveying activities conducted with CPP and DBP participants during the months of August through October of 2004 for the Demand Response Evaluation. This section presents an overall summary of the survey results that are explored in further depth throughout other sections of this report. The instruments for the Post-Event and the Final Evaluation survey modules are included in Appendix D and the resulting response tables are included in Appendix E.

5.1 OVERVIEW OF KEY FINDINGS

The Post-Event and Final Evaluation surveys conducted with CPP and DBP participants provide important information that can be used to better understand the likes and dislikes, barriers, and opportunities that participants reported for particular events as well as for their overall experience with the program as a whole. Highlights and key findings from these surveys include:

- Eighty percent of CPP participants surveyed reported taking DR actions for at least one of the specific CPP events on which they were surveyed. Eighty-four percent self-reported that they were either somewhat or very likely to take DR actions for future CPP events.

- Overall, SCE and SDG&E participants indicated low levels of bidding for DBP events, with only 27 percent of the DBP participants reporting that they placed bids for at least one of the DBP events on which they were surveyed. (PG&E DBP customers were not asked the series of bidding questions due to PG&E's different structure for day-of events in 2004 which did not allow actual bidding.) Three-quarters of DBP participants surveyed reported being somewhat or very likely to place bids for future events.

- Twenty-six percent of participants said they experienced impacts on their organization in terms of personnel comfort or productivity, such as lost production, staff complaints, and a warm or uncomfortable work environment.

- Only 5 percent of CPP and DBP participants surveyed who reported taking DR action for at least one event stated their organization increased their energy usage before the event occurred to make up for the reduction that was to occur and 17 percent reported they increased their energy use after the event to make up for what was lost.

- Half of respondents said that the notification timeframe, which allows an hour to place a bid after being notified of a DBP event, makes it less likely that they will place a bid.

- Eighty-six percent of CPP participants and 83 percent of DBP participants said they intended to participate in the DR programs next summer.

5.2 POST-EVENT AND FINAL EVALUATION SURVEY OVERVIEW

One of the key objectives of the Working Group 2 (WG2) Demand Response Evaluation was to carry out a series of surveys with program participants in order to record information regarding their participation, bidding and curtailment activities for recent CPP or DBP events. We refer to these as "Post-Event" surveys. This surveying activity would allow participants to provide real-time feedback on specific events while the experience was still fresh in their minds. The information gathered concerning the event-specific curtailment activities would also be valuable to inform the impact analysis because it provides additional detail about customers' activities for individual events. In addition to this surveying activity, a final end of summer evaluation survey was also desired, which would provide an overall assessment of participants' experiences with the CPP and DBP programs, their plans for future participation in these DR programs, and their thoughts on changes to the program that could help facilitate their participation.

QC initially planned to attempt contact with each of the CPP and DBP participants a maximum of three times during the summer event period (June through October) to collect information on their specific event experiences. However, because the utilities did not begin calling significant numbers of CPP or DBP events until late July or early August, a decision was made to reduce the number of post-event contact attempts to two. At the same, we decided to incorporate the final evaluation surveying activity into a second round of Post-Event surveys.

The initial Post-Event survey was conducted in late August and early September with 67 decision-makers responsible for one or more accounts signed up for the CPP or DBP programs. The second round of Post-Event surveys, conducted in late September and early October, included the Final Evaluation survey module and was completed with 137 decision-makers. Forty-three of the decision-makers were contacted during both the first and second round of surveys and thus the total number of unique customers surveyed was 161. The survey data was integrated across the multiple contacts and was analyzed to highlight important results that are presented in both this chapter and in Chapter 8 (CPP and DBP Process Evaluation).

The remainder of this section of the report is organized as follows:

- Section 5.3 presents the survey methodology;
- Section 5.4 through Section 5.7 present the Post-Event Results
  - CPP Event Participation (Section 5.4),
  - DBP Event Participation (Section 5.5),
  - Demand Reduction Actions (Section 5.6),
  - Notification Process (Section 5.7);
- Section 5.8 through Section 5.12 present the Final Evaluation Results
  - Reasons for Participation (Section 5.8),
  - Barriers to Participation (Section 5.9),
  - Program Satisfaction (Section 5.10),

- Likelihood of Further Participation (Section 5.11),
- General Market Perceptions (Section 5.12);

- Appendix D contains the telephone survey instrument for the Post-Event survey and Final Evaluation survey module; and
- Appendix E contains the survey frequency tables for the Post-Event and Final Evaluation surveys (broken down by utility, customer size, three customer business types and CPP or DBP participant).

5.3 SURVEY METHODOLOGY

This section describes the methods used to conduct the Post-Event and Final Evaluation surveys for the WG2 Demand Response Evaluation. It includes a discussion of the sample design, which includes details on the participant population, sampling plan and weighting scheme.

Participant Population Frame

Quantum Consulting created a population frame containing all PG&E, SCE and SDG&E accounts that signed up to participate in either the CPP or DBP program. The frame was updated monthly with current participants files provided by each utility. The participant population frame used to create the survey sample included participant updates through the end of July.

Sample Selection

The survey sample dataset began with the creation of a statewide database of participating premises. The sample design for both the Post-Event Survey and the Evaluation Wrap Up Survey targeted the decision-makers for all accounts signed for the CPP and DBP programs across the three utilities (PG&E, SCE and SDG&E). A limited number of participants were excluded from the sample due to the lack of contact information for the primary decision-maker. The sample was stratified based on the IOU service territory of the account or accounts the decision-maker was responsible for, the DR program the account(s) were enrolled in (customers signed up for both the CPP and DBP program were assigned to the CPP strata), and whether or not the account(s) had been active in the DR events (i.e., taken any curtailment actions during the events). Quotas for the 12 distinct strata were set to include all available decision-makers for all except the SCE DBP non-active participants stratum. At the time quotas were set there was a total of 189 unique DBP decision-makers in the sample, of which only 25 (or 13 percent) had placed bids for previous DBP events. Exhibit 5-1 below shows the distribution of the available sample and assigned quotas across the 12 strata. These numbers reflect the available sample for the second round of Post-Event surveys and the Final Evaluation survey module, which was slightly higher than the available sample for the initial Post-Event surveys due to additional contact information for decision-makers provided to Quantum from each of the utilities.

Exhibit 5-1
*Distribution of Available Sample and Quota for the Post-Event and Evaluation Wrap Up Surveys across the 12 Strata**

Strata	Utility	Active	Program	Sample	Quota
1	PG&E	1	CPP	28	28
2	PG&E	1	DBP	15	15
3	SCE	1	CPP	6	6
4	SCE	1	DBP	25	25
5	SDG&E	1	CPP	4	4
6	SDG&E	1	DBP	2	2
7	PG&E	0	CPP	4	4
8	PG&E	0	DBP	14	14
9	SCE	0	CPP	1	1
10	SCE	0	DBP	164	50
11	SDG&E	0	CPP	19	19
12	SDG&E	0	DBP	12	12
			Total	294	180

*"Active" refers to bidders for DBP. For CPP, "active" was defined as customers that showed at least 10 percent load reduction in one or more events.

Data Collection

Telephone interviews for both the Post-Event and Final Evaluation surveys were conducted with a representative group of decision-makers that were responsible for accounts participating in the WG2 DR programs from sample described above. The surveys were implemented by Quantum Consulting's Computer Aided Telephone Interview (CATI) center. As mentioned in the section above, customers were assigned to one of 12 strata based on their utility, whether they were enrolled in CPP or DBP, and whether they had taken any DR action in previous events.

The first round of Post-Event surveys was completed in late August and early September and asked DR participants questions concerning the CPP or DBP events they had experienced prior to the survey. Specifically, they were asked detailed questions about their participation in specific events (whether or not they had placed bids or had taken demand reduction actions and the types of actions taken), their likelihood of participating in future events, and their thoughts on the current notification process. In total the first round of Post-Event surveys was completed with 67 participants.

A second round of Post-Event surveys, which included the additional Final Evaluation module, was dialed in late September and early October and was completed with a total of 137 participants. Forty-three of these respondents had also completed the first round of Post-Event surveys. During the second round these 43 participants were asked about any CPP or DBP events that had occurred since the initial Post-Event survey has been administered. Once the questions from the Post-Event survey had been asked, the 137 survey respondents were asked a series of questions from the Final Evaluation survey module. This additional survey module included questions concerning reasons for participation, barriers to participation, program satisfaction, likelihood of further participation, and general market perception.

In total, 204 surveys were completed with 161 unique customer decision-makers. A summary of the surveys completed by survey module and survey contact is provided in Exhibit 5-2 below.

Exhibit 5-2
Number of Survey Completes by Survey Module and Customer Contact

	Survey Module			
Survey Contact	**Post Event**	**Final Evaluation**	**Total**	**Total Unique**
Initial Post Event Survey	67	n/a	67	67
2nd Post-Event / Final Evaluation Survey	116	137	137	94
Total	183	137	204	161

The final distribution of completes for the first round of Post-Event Surveys and the second round of Post-Event and Final Evaluation surveys are provided in Exhibits 5-3 and 5-4.

Exhibit 5-3
Distribution of Survey Completes for the First Round of Post-Event Surveys by Strata

Strata	Utility	Active	Program	Quota	Completes
1	PG&E	1	CPP	27	11
2	PG&E	1	DBP	16	5
3	SCE	1	CPP	6	4
4	SCE	1	DBP	17	8
5	SDG&E	1	CPP	4	1
6	SDG&E	1	DBP	2	0
7	PG&E	0	CPP	8	1
8	PG&E	0	DBP	13	4
9	SCE	0	CPP	1	0
10	SCE	0	DBP	50	28
11	SDG&E	0	CPP	6	4
12	SDG&E	0	DBP	6	1
			Total	156	67

Exhibit 5-4
Distribution of Survey Completes for the Second Round of Post-Event Surveys and the Final Evaluation Survey Module by Strata

Strata	Utility	Active	Program	Quota	Completes
1	PG&E	1	CPP	28	16
2	PG&E	1	DBP	15	9
3	SCE	1	CPP	6	2
4	SCE	1	DBP	25	16
5	SDG&E	1	CPP	4	2
6	SDG&E	1	DBP	2	1
7	PG&E	0	CPP	4	5
8	PG&E	0	DBP	14	13
9	SCE	0	CPP	1	0
10	SCE	0	DBP	50	52
11	SDG&E	0	CPP	19	12
12	SDG&E	0	DBP	12	9
			Total	180	137

Exhibit 5-5 shows the breakdown of survey completes for the two participant surveys by Utility.

Exhibit 5-5
Breakdown of Survey Completes by Utility

	Utility		
Survey Contact	**PG&E**	**SCE**	**SDG&E**
Initial Post Event Survey	21	40	6
2nd Post-Event / Final Evaluation Survey	43	70	24
Total	64	110	30

Exhibit 5-6 presents the breakdown of survey completes for the two participant surveys by the DR program in which the customer was enrolled. As Exhibit 5-6 illustrates there were three customers surveyed during the Initial Post-Event survey and four during the Final Evaluation survey that were enrolled in both the CPP and DBP program. These customers were asked about recent events for both the CPP and DBP programs.

Exhibit 5-6
Breakdown of Survey Completes by DR Program

	DR Program			
Survey Contact	**CPP**	**DBP**	**Both**	**Total**
Initial Post Event Survey	21	49	3	67
2nd Post-Event / Final Evaluation Survey	37	104	4	137
Total	58	153	7	204

Representativeness

The responses to the survey questions in this section are shown un-weighted and thus represent the distribution of the customers surveyed, not necessarily the entire participant population. To account for the fact that the SCE DBP bidding population was over-sampled, and for the possible response bias that could exist since customers who are active in these DR programs are probably more likely to take the time to participate in these surveying activities, certain questions have been broken out by whether customers took bidding or demand reduction actions. Exhibit 5-7 shows the percentage of unique CPP and DBP respondents who reported placing bids for at least one DBP event or taking DR action for a CPP or DBP event.

Exhibit 5-7
Percentage of CPP and DBP Survey Respondents who Reported Placing Bids or Taking Curtailment Actions for Recent DR Events

	Unique DR Participants			
	CPP	**%**	**DBP**	**%**
Total Surveyed	46	100%	122	100%
Reported Placing DBP Bid*	-	-	26	27%
Reported Taking DR Actions	37	80%	51	42%

* SCE and SDG&E Only

Specific Events Included in Post-Event Interviews

During both the first and second rounds of Post-Event surveys respondents were asked about the DR actions they took for a specific set of recent CPP and/or DBP events. Each customer was asked about one to three distinct events during each survey. Thus participants who completed both surveys could have been asked about a maximum of six unique events. The number of distinct events included in the survey for each customer was based upon the number of events that had occurred since the customer signed up for the DR program (excluding events that had been discussed in the first round of surveys for the 43 customers who were contacted twice). The maximum number of events included per survey was set to three in order to keep the surveys to a reasonable length of time. Exhibit 5-8 below provides the sum of the total number of specific CPP and DBP events asked about over all customers surveyed during the first and second round of the survey contacts.

Exhibit 5-8
Total Numbers of CPP and DBP Customer-Events Captured Over All Survey Respondents

	DR Program		
Survey Contact	**CPP**	**DBP**	**Total**
Initial Post Event Survey	39	51	90
2nd Post-Event / Final Evaluation Survey	111	152	263
Total	150	203	353

The first round of Post-Event surveys was completed with 21 customers who were signed up for the CPP program (from Exhibit 5-6 above). On average, these customers were asked about approximately two specific CPP events for a total of 39 events across all customers. In the month of September, PG&E and SDG&E both called 3 CPP events and SCE called 8 CPP events; thus during the second round of surveys it was possible to ask all CPP customers about three events (the maximum allowed). For DBP, the average number of DBP events customers were asked about in the first round of interviews was close to one (51 DBP customer-events for 49 customers), and for the second round the average jumped to 1.5 (152 customer-events for 104 customers). Exhibit 5-9 below provides the average and distribution of the number of events asked about for each survey respondents over both survey contacts.

Exhibit 5-9
Distribution and Average of Number of Events Included in Survey for all Unique Participants

	DR Program		
Number of Events	**CPP**	**DBP**	**Total**
1	4	50	54
2	0	63	63
3	30	9	39
4	8	0	8
5	0	0	0
6	4	0	4
Total	150	203	353
Average # Events	3.3	1.7	2.1

Customers with Multiple Facilities

As shown in Exhibit 5-2 above, there were a total of 161 unique customers contacted during the Post-Event or Final Evaluation surveys. Many of the customers contacted were responsible for more than one facility enrolled in the CPP or DBP programs. The customers contacted represented a total of 449 unique facilities (accounts) enrolled in the DR programs. Exhibit 5-10 below shows the number of facilities included in the surveys for the CPP and DBP programs.

Exhibit 5-10
Total Number of CPP and DBP Facilities Assigned to Decision-Makers Surveyed

	DR Program		
Survey Contact	**CPP**	**DBP**	**Total**
Initial Post Event Survey	46	64	110
2nd Post-Event / Final Evaluation Survey	71	268	339
Total	117	332	449

Exhibit 5-11 below shows that of the 46 unique CPP customers contacted during the surveys, approximately 65 percent (or 30 participants) were responsible for only one facility signed up for the CPP program. Overall, the CPP participants surveyed were responsible for a total of 90 unique facilities enrolled in the program for an average of two facilities per customer surveyed.

For DBP, 98 of the 122 DBP participants surveyed were for only one facility signed up for the DBP program (roughly 80 percent). As shown in Exhibit 5-11 below, the average number of facilities per DBP participant surveyed was 2.4; however, that is significantly skewed by the single customer who had enrolled 120 unique facilities in the program. With this customer removed the average falls to 1.4 facilities per customer.

Exhibit 5-11
Distribution and Average of Number of Facilities for all Unique Participant Surveyed

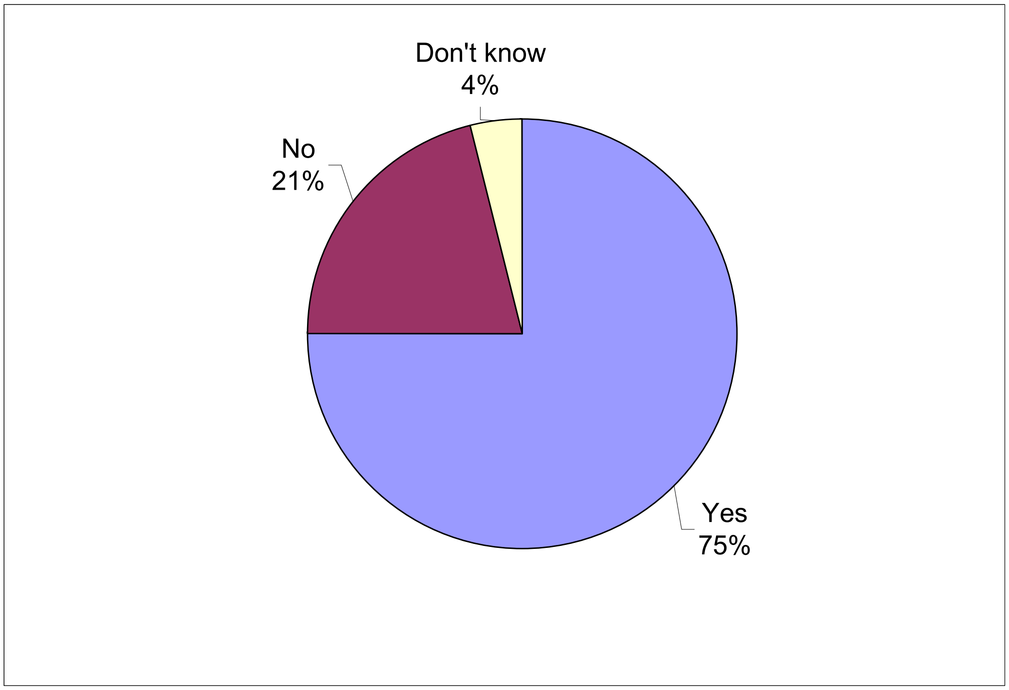
	DR Program		
Number of Facilities	**CPP**	**DBP**	**Total**
1	30	98	128
2	7	13	20
3	2	3	5
4	2	0	2
5	2	5	7
6	0	0	0
7	2	1	3
8	1	1	2
120	0	1	1
Total	90	293	383
Average # Facilities	2.0	2.4	2.3

5.4 CPP EVENT PARTICIPATION

A series of questions was asked of CPP participants to gain information about their level of participation in the program and their likelihood of participating in future CPP events. The complete set of responses to these questions broken down by utility, customer size, and business type are provided in Appendix E.

In total, 46 unique CPP participants were asked about their participation in a series of CPP events this past summer. Each of these participants was asked about one to six events (distribution provided in Exhibit 5-9) for a total of 150 unique customer-event combinations. Overall, participants indicated a fairly high-level of participation in the CPP events with 37 of the 46 CPP participants (roughly 80 percent) reporting that they took DR actions for at least one of the CPP events included in the survey (shown in Exhibit 5-7 above). On an individual event basis CPP participants reported taking DR actions for 75 percent of the 150 events in question. The overall participation breakdown across the 150 events is shown in Exhibit 5-12 below.

Exhibit 5-12
Percent of CPP Events for which Participants Took Demand Reduction Actions (N=150)



Of the 16 CPP participants who were responsible for multiple facilities signed up for the CPP program, 13 reported taking action for one or more of the CPP events. Of these 13 customers, roughly two-thirds reported taking demand reduction actions at all of their facilities (9 customers).

Customers who reported that they did not take demand reduction actions for a particular event were asked for the reasons why they did not respond to that event. In total there were 31 customer-event combinations for which the customer reported that no DR actions were taken. The primary reasons given for not shutting down for these events were that they "Could not shut down", "Operation was already shut down", and "No one was available to reduce load," among other responses as seen in Exhibit 5-13 below.

Exhibit 5-13
Self-Reported Reasons for Not Taking Actions for Specific CPP Event

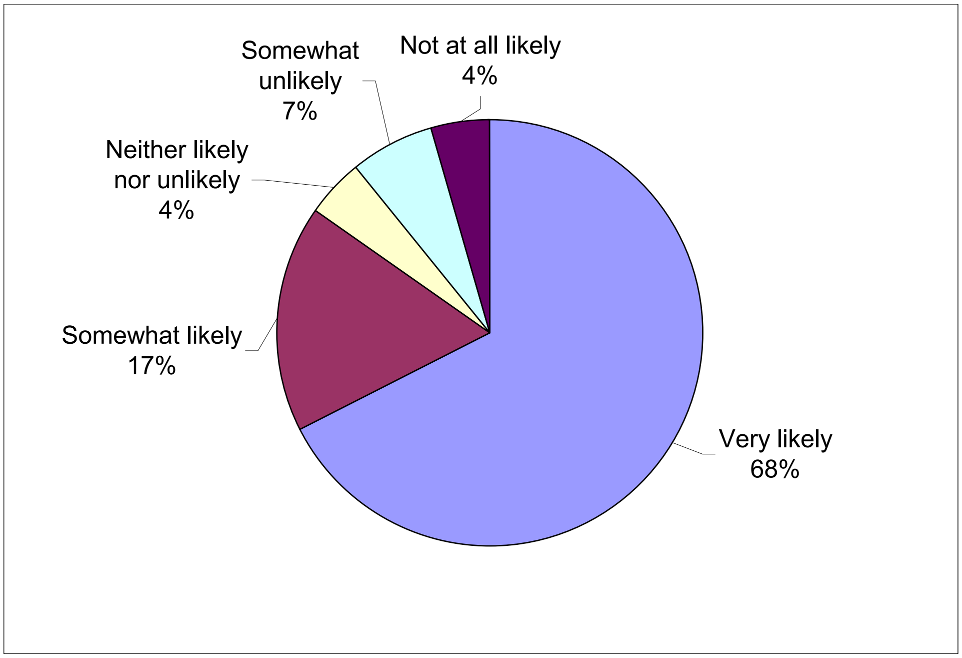
CPP1_C. Why didn't your firm take any demand reduction action?	Total
Could not shut down	32%
Operation was already shut down	19%
No one was available to reduce load	13%
Don't need to take action to save money	10%
Could not respond that fast	10%
Other	10%
Did not get the message	3%
Other priorities	3%
N	31

* N is the number of customer-events.

The reason stated for 10 percent of CPP events for which no DR action was taken was that the participants did not need to take action to save money. It is important to note that the total number of events being reported on was only 31 and thus the 10 percent represents only 3 customer-event combinations.

When each of the CPP participants was asked about their likelihood of taking demand reduction actions in future CPP events, 84 percent responded that they were either somewhat or very likely to take actions for future events. Only 4 percent of participants reported they were not at all likely to take action and 7 percent reported they were somewhat unlikely. The complete distribution across all unique CPP participants is shown in Exhibit 5-14 below and demonstrates a relatively high future interest in the CPP program.

Exhibit 5-14
Likelihood of Taking Demand Reduction Actions in the Future
For CPP Events (N=46)



All CPP participants were also asked what their utilities could do to help them take demand reduction actions for future CPP events. The majority of the respondents (62 percent) reported that there was nothing the utilities could do to help them. However, of those who offered suggestions for additional aid the utilities could provide to their customers, the majority mentioned increased advertising of the program to the general public[1] and improvements to the notification process that would allow for more notification options, increased warning before an event, and real-time or post-event feedback on their performance.

5.5 DBP EVENT PARTICIPATION

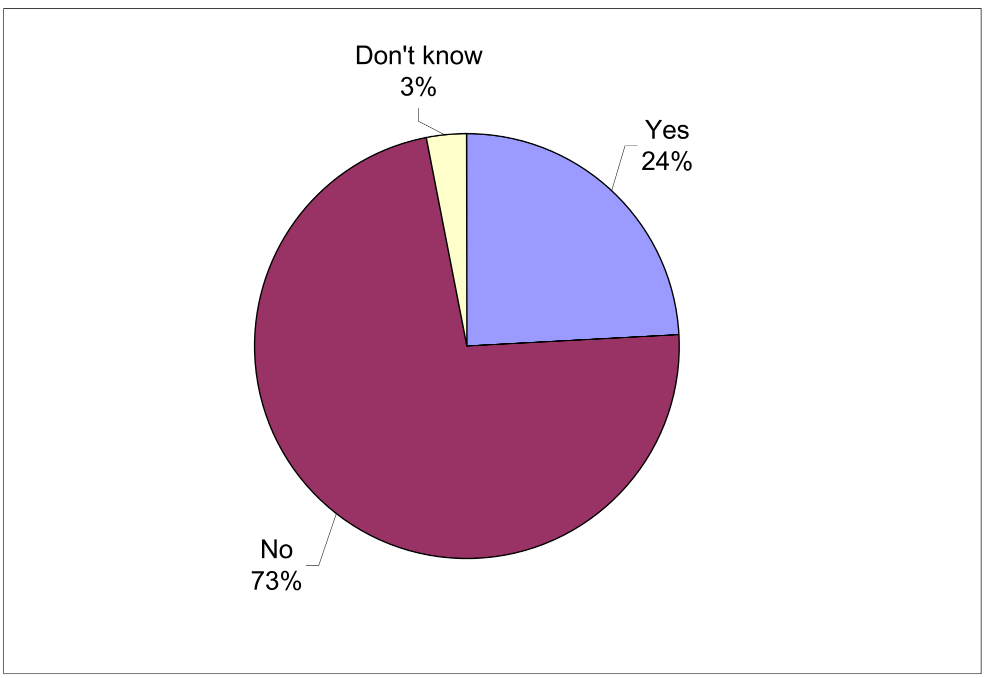
A series of similar questions was asked of DBP participants to gain information about their level of participation in the program (both in terms of bidding, if applicable, and demand reduction actions) and their likelihood of participating in future DBP events. The complete set of responses to these questions broken down by utility, customer size, and business type is provided in Appendix E. When reviewing this section it is important to keep in mind that during the course of this past summer no real DBP events were ever called for SCE or PG&E. The only DBP events called for these two utilities were day-of "test" events. Although SDG&E did call two non-"test" events (one was a system emergency and one was a system constraint) they, too, were day-of events as opposed to day-ahead events. As a result, the participants' opinions regarding the DBP events from this past summer could be different from what they

[1] Appendix Exhibit E-5 (CPP Suggestions)

would be during a summer that had a mixture of price- or reliability-triggered day-of and day-ahead events.

In total, 122 unique DBP participants were asked about their participation in a one or more of the DBP events this past summer. Each participant was asked about between one and three events (distribution provided in Exhibit 5-9) for a total of 203 unique customer-event combinations. The DBP questions for SCE and SDG&E DBP participants began by asking them about whether or not they placed bids for any of the specific DBP events (176 customer-event combinations). PG&E customers were not asked these same questions about bidding due to the fact that PG&E had only one DBP event this summer and since it was a day-of "test" event participants were not allowed to place a bid. This was because performance and payments for PG&E for day-of events were determined relative to a "committed load", which customers specified when signing up for the program. (For 2005, PG&E has proposed to convert to true day-of bidding for 2005.) Overall, SCE and SDG&E participants indicated low levels of bidding for DBP events, with only 27 percent of the DBP participants reporting that they placed bids for at least one of the DBP events included in the survey (shown in Exhibit 5-7 above). On an individual event level DBP participants reported placing bids for 24 percent of these 176 customer-events, as seen in Exhibit 5-15 below.

Exhibit 5-15
Percent of DBP Events for which Participants Placed Bids (SCE and SDG&E Only, N=176)



Customers who reported they did not place a bid for a particular event were asked why they did not place a bid for that event. The response given most often for not bidding for a specific event was that the participant was unable to reduce load on that particular day (39 percent of the events). For 10 percent of the events, the participants reported that they never planned to bid for any DBP event (this corresponded to 6 customers or 8 percent of the DBP participants surveyed). Another response given for non-bidding for 10 percent of the events was that the person responsible for bidding was not available that day. Not having enough time to respond and other system issues were both given as reasons for nine percent of events in which bids were not placed. Four percent responded they did not place a bid for a certain event due to the cancellation of the event, which indicates that customers sometimes confused the dates of the events since the one SCE cancelled event was not included in the survey. A complete listing of the reasons provided for not placing bids for specific events in Exhibit 5-16 below.

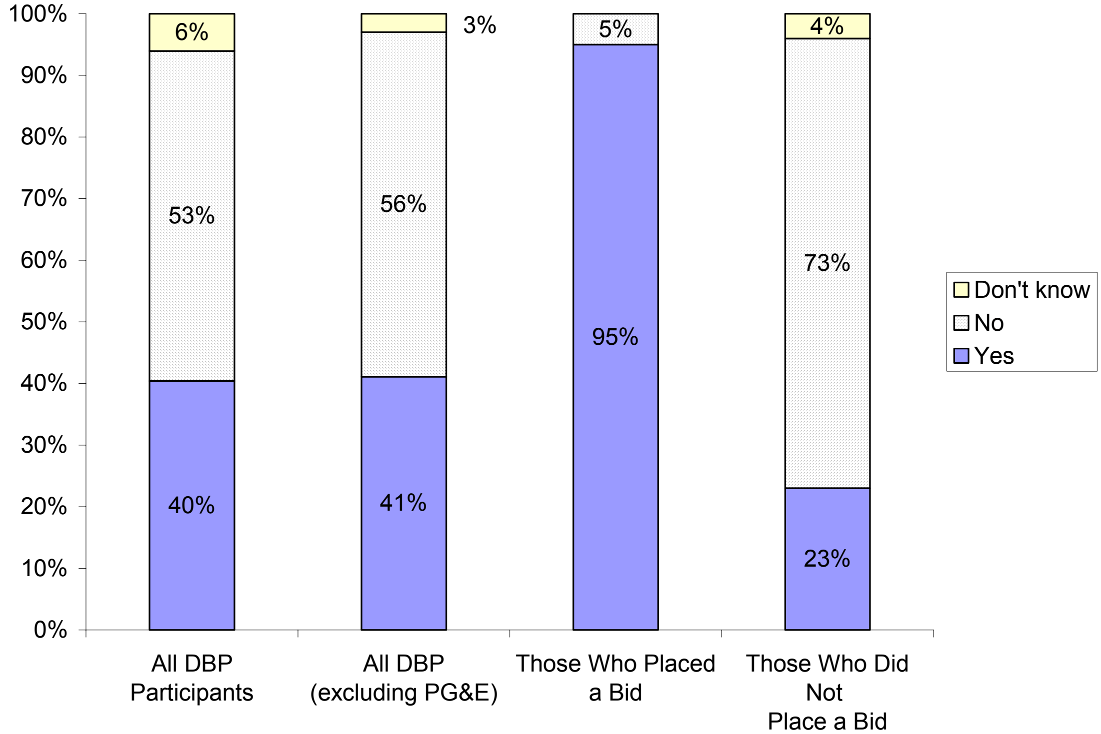
Exhibit 5-16
Self-Reported Reasons for Not Placing Bids for Specific DBP Events

DBP1_C. Why didn't your firm place a bid for the DBP event?	Total
Could not reduce load on that particular day	39%
Never planning to bid for any event	10%
People responsible for bidding were not there	10%
System issue/no password	9%
Did not get notification in time	9%
Could not respond that fast	4%
Not available to bid that hour	4%
The event was cancelled	4%
Operation was already shut down	3%
Other	3%
Don't need to take action to save money	2%
Unhappy with first bid	2%
Don't know	4%
N	128

* N is the number of customer-events.

DBP participants were also asked if they had taken demand reduction actions for the DBP events regardless of whether or not they had placed a bid. Overall DBP participants indicated moderate levels DR actions for DBP events with 42 percent of the DBP participants reporting they took action for at least one of the DBP events included in the survey (shown in Exhibit 5-7 above). On an individual event level, 122 DBP participants were asked about a total of 203 events (this is greater than those asked about bidding since PG&E customers were included in the DR actions questions). Although SCE and SDG&E DBP participants indicated placing bids for only 24 percent of the DBP events, they reported taking DR actions for 41 percent of DBP events (40 percent if the PG&E DR action responses are included). The 17 percent difference between the percent of events for which bids were placed, versus the percent of events where curtailment actions were reported to have occurred, is driven by customers who reported taking DR actions for DBP events despite the fact that they did not bid (this action was reported for 23 percent of the events in which bids were not placed). SCE and SDG&E participants who placed a bid for a specific event reported they were equally likely to take demand reduction actions, however, participants in SDG&E territory who did not place a bid reported a higher likelihood than SCE participants to still take demand reduction actions (50 versus 19 percent).[2] Nearly all customers who placed bids for DBP events reported that they also took DR actions for those events (95 percent). Exhibit 5-17 below shows the percent of DBP event for which DBP participants took DR actions.

Exhibit 5-17
Percent of DBP Events for which Participants Took Demand Reduction Actions
(N=203 for All DBP Participants and N=176 for All DBP excluding PG&E)



DBP customers who reported they did not take demand reduction actions for a particular event were asked for the reasons why they did not take any actions for that event. In total there were 106 customer/event combinations for which the customer reported that no DR actions were taken. Again, similar to the reasons given for not bidding on certain events, the most common response for not taking action was "Could not reduce load on that particular day" (42 percent). Other frequent responses included "Was not a mandatory reduction" and "Person in charge of shutdown was not there", among others, as seen in Exhibit 5-18.

2 Appendix Exhibit E-10 (DBP Bid and Action); Appendix Exhibit E-11 (DBP No Bid and Action)

Exhibit 5-18
Self-Reported Reasons for Not Taking Action for Specific DBP Events

DBP1_E. Why didn't your firm take any demand reduction actions for this event?	Total
Could not reduce load on that particular day	42%
Was not a mandatory reduction	8%
Person in charge of shutdown was not there	8%
Other	7%
Not available to bid that hour	6%
Did not get notification in time	5%
We are on an interruptible rate schedule	5%
System issue/no password	5%
Operation was already shut down	4%
Could not respond that fast	4%
Never planning to bid for any event	4%
No reason	2%
Do not remember why	1%
Don't know	4%
N	106

* N is the number of customer-events.

DBP customers who reported placing bids and also taking demand reduction actions for specific DBP events were also asked how their actual reduction for the event compared to what they bid. For 41 percent of these events, participants stated their actual reduction was close to what was bid, for 17 percent of events the reduction was less than what was bid, and for 15 percent of events the reduction was more than was bid. When asked the reasons why their actual reductions for an event differed from what they bid, participants gave reasons such as "We use such little energy, it's hard to reduce more," "We did not have time to track curtailment," and "Incentives were too low, not worth lost productivity."[3]

All DBP participants were asked about their likelihood of placing bids for future DBP events and nearly three out of four participants (72 percent) responded they were somewhat or very likely to place bids for future events. Only eight percent said they were not at all likely to place a bid, however 16 percent reported that they were somewhat unlikely.[4] The complete distribution across all unique DBP participants is shown in Exhibit 5-19 below. Three participants were dropped from this Exhibit since they were currently unsure of their future participation.

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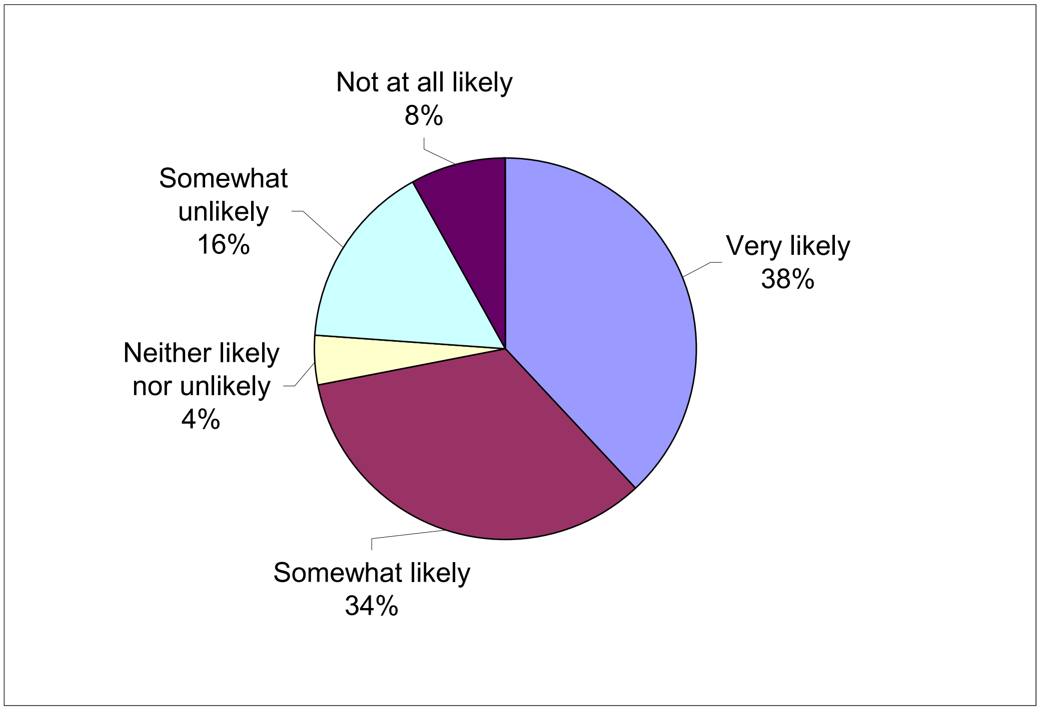
[3] Appendix Exhibit E-14 (DBP Bid and Action Comparison); Appendix Exhibit E-15 (DBP Reasons for Reduction Difference)

[4] Note that this result may be sensitive to response bias – that is, DBP participants who are least likely to place bids in the program may be least likely to participate in our program evaluation survey.

Exhibit 5-19
Likelihood of Placing a Bid for Future DBP Events (N=119)



This question was analyzed further after first excluding PG&E DBP participants, since they were not allowed to place bids for the single DBP "test" event that was called this summer, and then calculating the likelihood distribution on the remaining participants. This population comprised of SCE and SDG&E participants also reported a high likelihood of placing a bid for future DBP events (70 percent without PG&E versus 72 percent with PG&E reporting very or somewhat likely). However, when the responses of the SCE and SDG&E DBP participants were broken down further by whether or not they reported bidding on any of the DBP events, the resulting distribution of future program participation changed significantly. While 65 percent of bidders reported that they were very likely to place bids on future DBP events, only 26 percent of the non-bidders reported this same likelihood. The percentage of participants surveyed reporting they were very unlikely or somewhat unlikely to place bids for future DBP events was 12 percent for those who had bid in the past versus 33 percent of those who had not previously bid. A complete breakdown of likelihood of bidding on future DBP events by previous bidding history is provided in Exhibit 5-20.

Exhibit 5-20
Likelihood of Placing a Bid for Future DBP Events – Bidders versus Non-Bidders

	ALL	Bidders			Non-Bidders		
What is the likelihood that you will place bids for future DBP events?	SCE and SDG&E	Total	SCE	SDG&E	Total	SCE	SDG&E
Very likely	37%	65%	68%	57%	26%	29%	0%
Somewhat likely	33%	23%	16%	43%	37%	38%	20%
Neither likely nor unlikely	3%	0%	0%	0%	4%	5%	0%
Somewhat unlikely	19%	8%	11%	0%	24%	21%	60%
Not at all likely	7%	4%	5%	0%	9%	8%	20%
N	94	26	19	7	68	63	5

* N is the number of respondents.

When asked what their utilities could do to help participants bid on future DBP events, about half of respondents (52 percent) said "Nothing". The only other suggestion given by more than one or two customers was to give more notice before an event (26 percent of DBP participants gave this response).[5]

When participants were asked how their DR program participation this past summer has impacted their knowledge of how to manage their energy use, most participants (62 percent) stated they are now somewhat more knowledgeable about managing their energy usage at times of peak demand. Fifteen percent reported they are now much more knowledgeable and 23 percent said they are no more knowledgeable.[6]

5.6 DEMAND REDUCTION ACTIONS

For customers reporting they had taken demand reduction actions for one or more of the CPP or DBP events this past summer, a series of questions was asked about the specific DR actions taken and the effects these reductions had on the customers' organizations. The complete set of responses to these questions, broken down by utility, customer size and business type, are provided in Appendix E.

Customers who reported taking DR actions for at least one DR event this past summer were asked specifically what types of actions they took to reduce their energy usage. The curtailment actions reported most often by the CPP and DBP participants who took action included reducing lighting levels (29 percent), allowing the temperature in occupied spaced to rise (28 percent), and shutting down production either partially or completely (28 percent). The

[5] Appendix Exhibit E-17 (DBP Suggestions)

[6] Appendix Exhibit E-95 (Knowledge)

complete list of demand reduction actions reported for CPP and DBP events this past summer is provided in Exhibit 5-21.

Exhibit 5-21
Demand Reduction Actions Taken for CPP and DBP Events

EV10. What demand reduction actions did you take in response to the most recent event in which you participated?	Total
Reduced overhead lighting	29%
Allowed temperature to rise in the occupied spaces	28%
Reduced or shut off some or all production processes	28%
Turned off non-critical equipment	21%
Shut down partially	13%
Used back generators	12%
Shut down completely	10%
Other	6%
Rescheduled EMS	3%
N	86

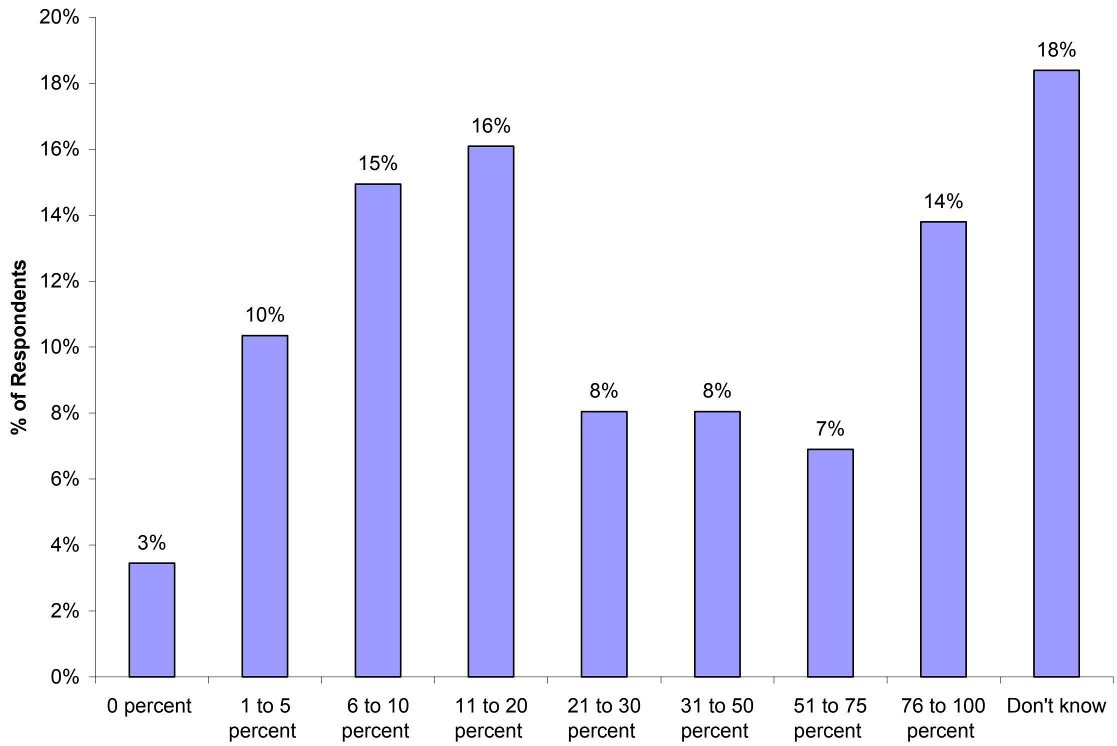
* N is the number of respondents.

Customers were then asked whether they implemented their curtailment actions manually or in an automated fashion. Seventy-seven percent of those who took action reported that they implemented these demand reductions manually, 16 percent reported they were partially automated, and 6 percent said they were fully automated.[7]

CPP and DBP participants who had taken DR actions were asked to estimate the load reduction attained as a result of their curtailment for the most recent event in which they participated. Eighteen percent of the respondents reported being unsure of the magnitude of their load reduction. Forty-five percent of the respondents who could provide a load reduction estimate reported that their reduction was greater than 30 percent of their total load. The distribution of these self-reported responses is shown in Exhibit 5-22.

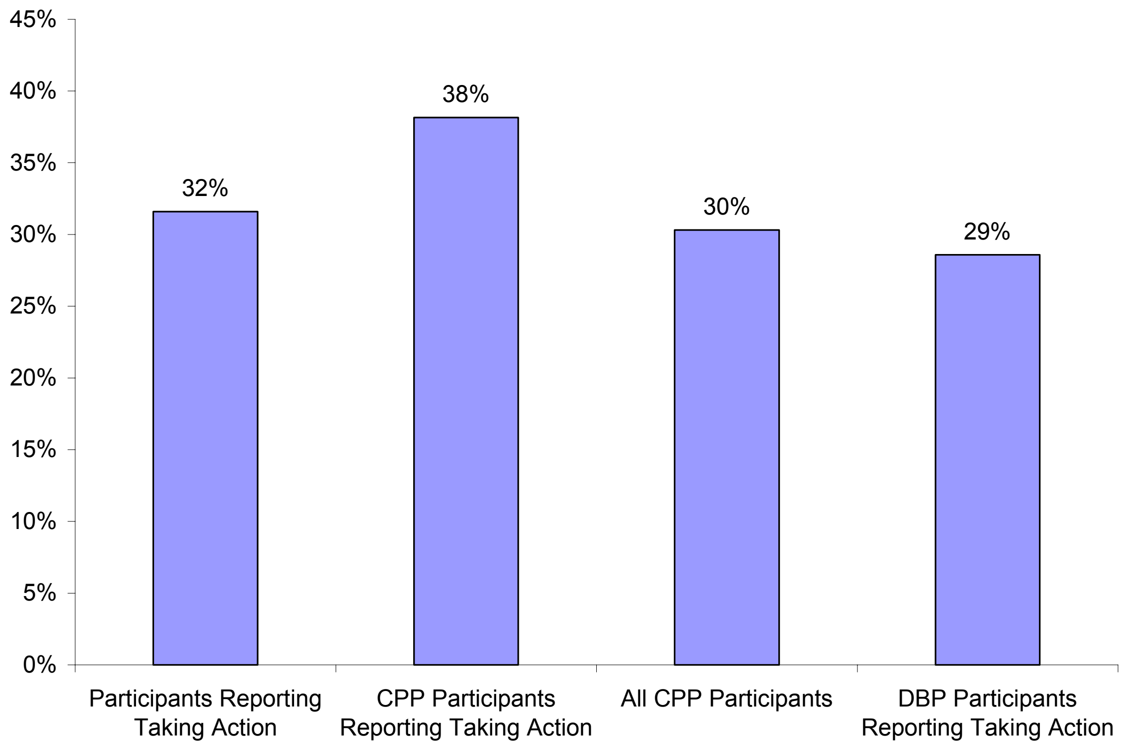
[7] See Appendix Exhibit E-19 (Implementing Reductions)

Exhibit 5-22
Self-Reported Load Reduction Attained from Curtailment for Participants that Took Action



Taking the midpoint from each of the load reduction ranges above and excluding respondents who reported they "Don't Know" how much of their load they reduced, the average self-reported load reduction for people who claimed to take action during an event was calculated to be 32 percent. Conducting a similar analysis on CPP and DBP participants separately showed that on average CPP participants believe their curtailment actions resulted in load reductions that were one-third larger than those self-reported by DBP participants. This is illustrated in Exhibit 5-23. Note that, for CPP, the resulting averages from these customer self-reports are higher than the savings found in the impact evaluation (see Chapter 7). This is likely due to a combination of several factors including customer over-reporting, response bias in the sample (e.g., a larger share of the sample than population may have taken actions), and the sample being over-weighted toward SDG&E and SCE customers (which had smaller populations of participants but higher average savings than the PG&E group).

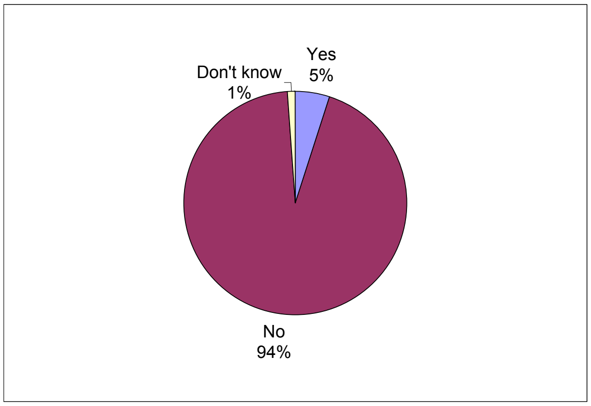
Exhibit 5-23
Self-Reported Unweighted Average Load Reduction from Curtailments
(Note that actual measured impacts are significantly different, see Chapter 7)



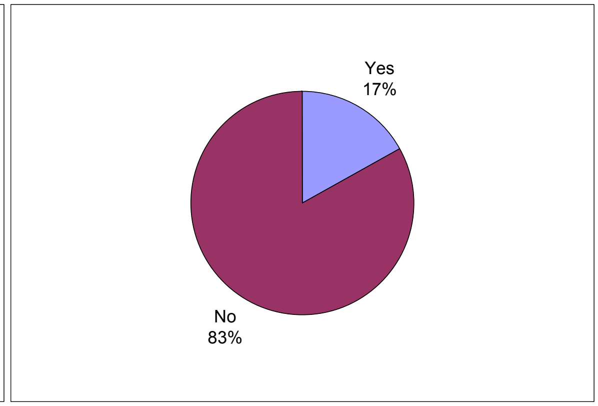
To get a better understanding of how customers are responding to the CPP and DBP events and how their curtailment actions impact their daily load shapes, customers were asked whether before or after the event they increased their energy usage for a period of time to make up for their reduction. As Exhibit 5-24 shows, only 5 percent of participants who reported taking DR action for at least one of the events stated they increased their energy usage before the event and 17 percent reported increasing their energy use after the event.

Exhibit 5-24
CPP and DBP Participants who Increased their Energy Usage

Before Event (N=87)



After Event (N=87)



CPP and DBP participants were asked whether or not they experienced any impacts on their organization in terms of personnel comfort or productivity as a result of their curtailment actions. Overall, 26 percent reported that their organization experienced impacts as a result of their participation in the DR event. The primary negative effects reported, of those impacted, were lost production (38 percent), staff complaints (28 percent), and a warm or uncomfortable work environment (24 percent).[8] It is interesting to note that only 10 percent (3 respondents) specifically mentioned that the impacts were financial, although those who gave lost production as an impact may have felt that financial impacts were therefore assumed.

5.7 NOTIFICATION PROCESS

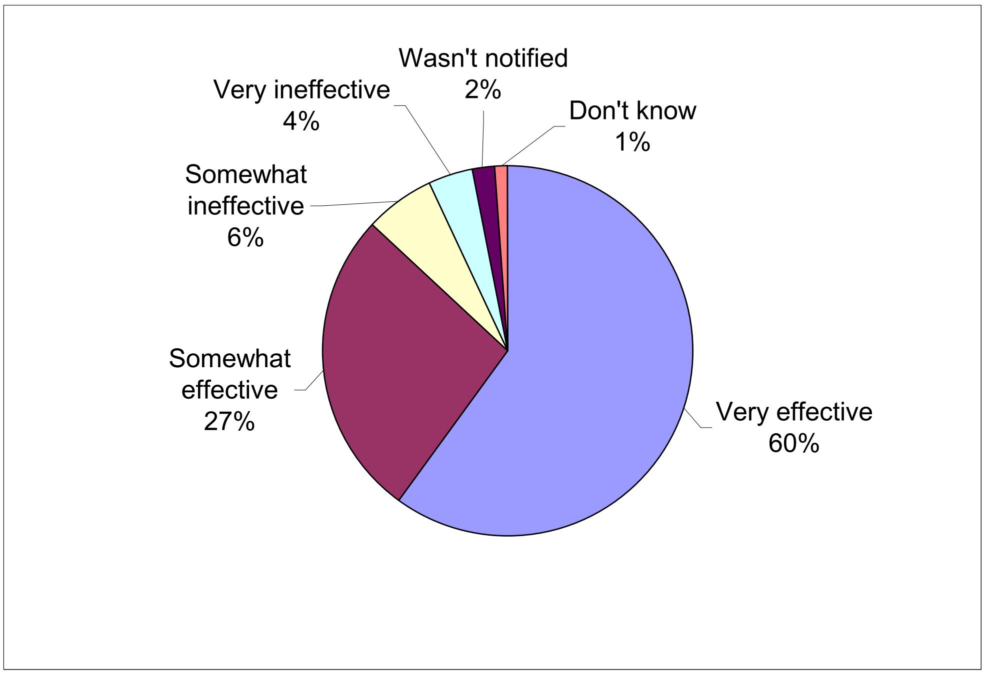
CPP and DBP participants were asked several questions about the event notification process to determine its effectiveness and the resulting impact it had on their curtailment actions for the CPP and DBP events. A complete set of responses to the notification questions, broken down by utility, customer size, and business type, are provided in Appendix E. Additional discussion of these questions in the context of the overall CPP and DBP process evaluation is also provided in Chapter 8.

All customers surveyed were asked about their opinion regarding the effectiveness of the process in which they were notified about the DR event. Overall, participants considered the notification process to be effective, as seen in Exhibit 5-25. Eighty-seven percent said the notification process was somewhat or very effective, and only 10 percent reported that it was somewhat or very ineffective. Effectiveness was ranked slightly higher by CPP participants (93 percent reporting very or somewhat effective) than it was for DBP participants (85 percent reporting very or somewhat effective), which could relate to the fact that the CPP notification requires no immediate action on the part of the participants, whereas the DBP notification

[8] Appendix Exhibit E23 (Organization Impacted); Appendix Exhibit E-24 (Impacts on Organization)

requires that participants have immediate access to their computers so they can place their hourly bids on the utility websites. It is important to note here that the DBP events called this summer at all of the utilities were day-of test or emergency events. Although these events give participants less time to put there curtailment plans in motion, the timeframe participants are given to respond (between the event notification and the time bids are due) is the same (1-hour) as for the day-ahead events. However, in the absence of DBP day-ahead events it is impossible to know if of how these results would change for a summer that include day-ahead DBP events in addition to day-of events.

Exhibit 5-25
Effectiveness of the Notification Process (N=161)



Participants reporting that the notification process was somewhat or very ineffective were asked why they believed this to be the case (N=15). The most common reason respondents gave for considering the notification process to be ineffective was that the notice was received too late, thereby not giving them enough time to bid (47 percent). Other reasons participants gave for claiming the notification was ineffective were "Notice was emailed and didn't check email," and "Cannot bid if out of office."[9]

When asked about whether or not they were aware that they could receive a courtesy notification (an additional notification via the channel of their choice, i.e., pager, fax, etc.) most

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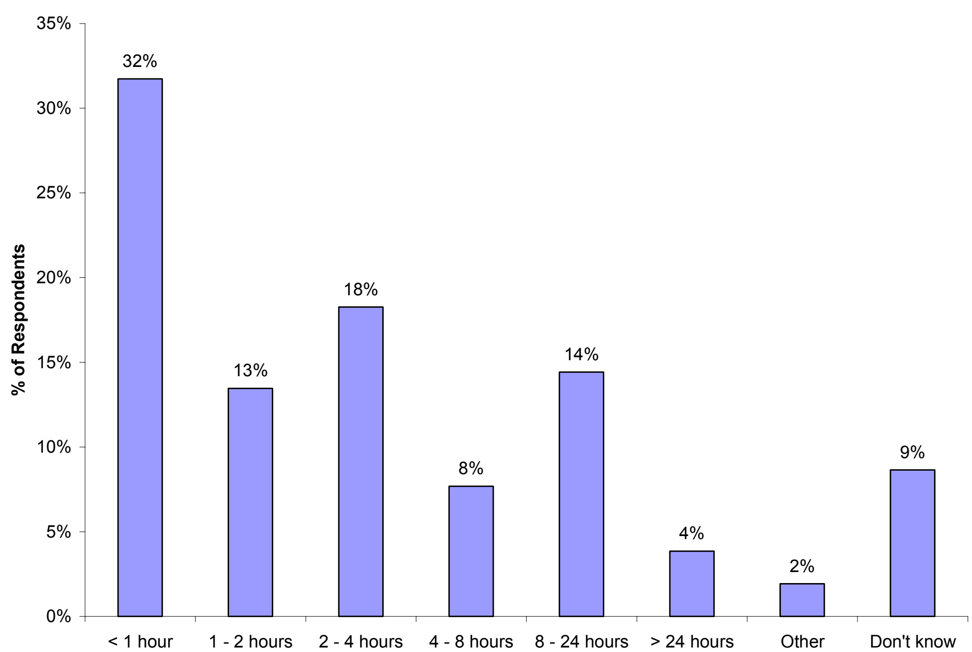
[9] Appendix Exhibit E-26 (Reasons for Notice Effectiveness)

CPP and DBP participants survey reported they were aware (80 percent). Of those who reported awareness of the courtesy notification, 84 percent reported were signed up for one.[10]

DBP participants surveyed were asked whether the notification timeframe, which allows an hour to place a bid after being notified of a DBP event, makes it less likely that they will place a bid for a DBP event. Half of the respondents reported that the one-hour timeframe was not adequate. When asked why this was the case, the main reasons given were that they "cannot react that quickly" (45 percent) and that "the person in charge of bidding is busy and hard to reach" (38 percent). Another frequently reported reason was "it takes time to coordinate a shut down within the company."

DBP participants were asked, ideally, how much time they would need to submit a bid after they have been notified. Although one in three respondents (32 percent) said they only needed an hour to submit a bit, about half (53 percent) said they need between 1 and 24 hours, and 4 percent said they need more than 24 hours. The distribution of the number of hours required to submit a bid is displayed in Exhibit 5-26 below.

Exhibit 5-26
Time Required to Submit a Bid



DBP participants were also asked how their bidding time requirement differs for day-of events as compared to day-ahead events. Half of respondents reported there was no difference, however, of the remaining half, 24 percent stated day-of events were extremely difficult or

10 Appendix Exhibit E-28 (Courtesy Notification Awareness); Appendix Exhibit E-29 (Courtesy Notification)

impossible to participate in and 40 percent said they needed more time or an earlier notification in order to bid for day-of events.[11]

When asked how much time it takes to curtail load in response to the announcement of a CPP or DBP event, half of all respondents said one hour or less or reported that the current process is adequate. An additional 26 percent reported needing between 1 and 4 hours and the remaining 24 percent said they needed more 4 hours and as much as 2 days. [12]

5.8 REASONS FOR PARTICIPATION

As part of the final evaluation survey, CPP and DBP respondents were asked to rate the significance of several factors on their decision to participate in the demand response program. A complete set of responses to the participation questions, broken down by utility, customer size, and business type, are provided in Appendix E. Additional discussion of customers' reasons for participating in these programs in the context of the overall CPP and DBP process evaluation is provided in Chapter 8.

All of the factors asked about received similar ratings, with each having a mean rating of about a 4 on a scale from 1 to 5, where a 1 is insignificant and a 5 is extremely significant. Being able to participate in the program without significantly affecting business practices was the most significant of the four factors, followed closely by avoiding rolling blackouts, the amount of potential bill savings, and being a good corporate citizen. The mean significance ratings are provided in Exhibit 5-27.

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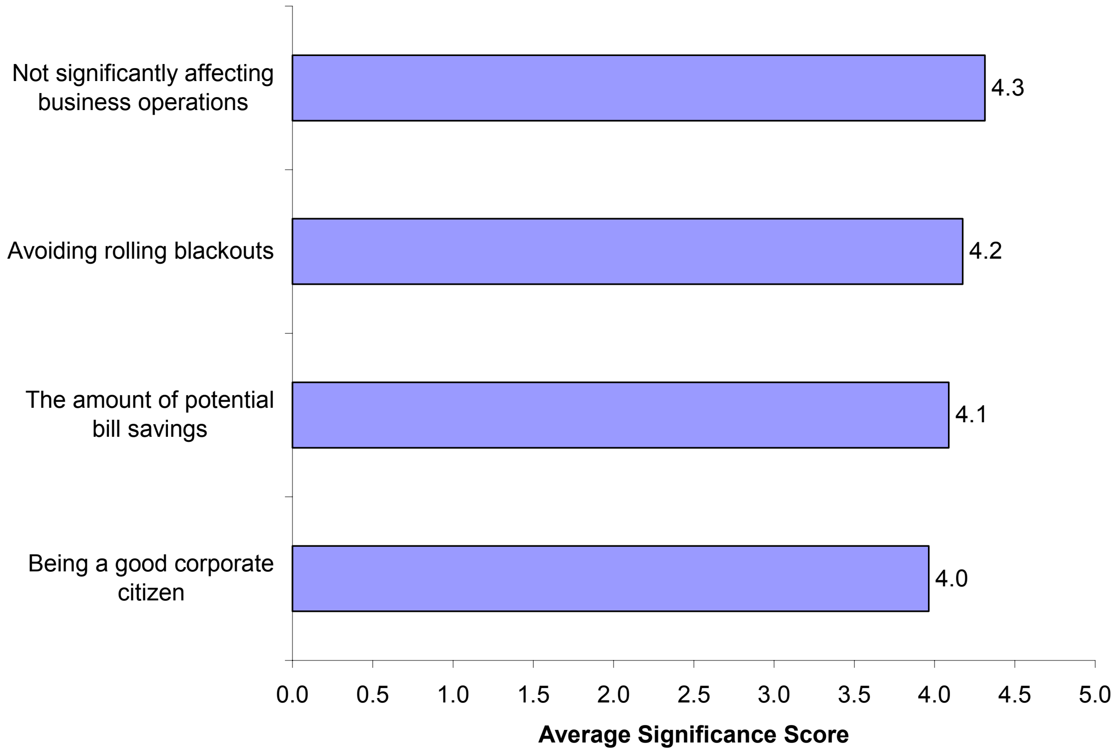
[11] Appendix Exhibit E-34 (Day of Events)

[12] Appendix Exhibit E-35 (Time to Curtail)

Exhibit 5-27
Mean Significance Rating

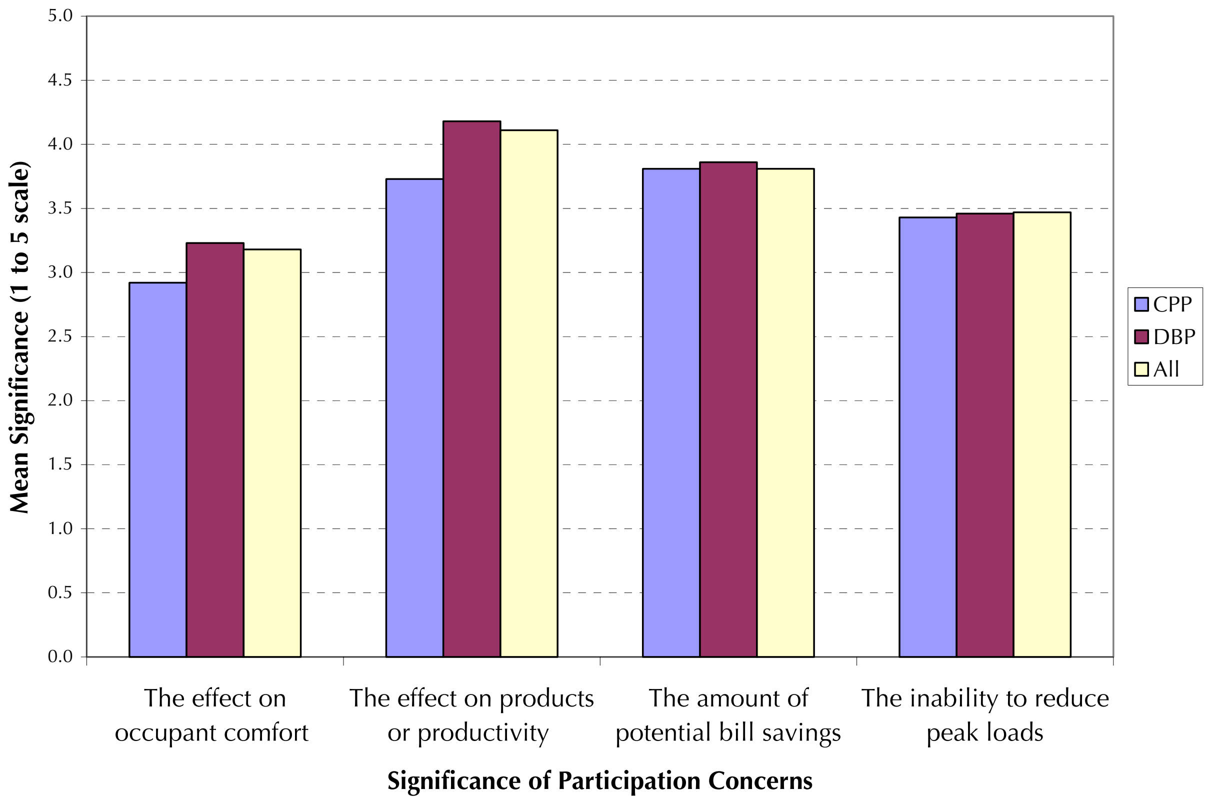


5.9 BARRIERS TO PARTICIPATION

As part of the final evaluation survey CPP and DBP customers were asked to rate the significance of several concerns that might be considered barriers to participation for some organizations. A complete set of responses to the barrier questions, broken down by utility, customer size, and business type, are provided in Appendix E. Additional discussion of the barriers customers face with regards to participation in DR programs is provided as part of the CPP-DBP Process Evaluation (Chapter 8).

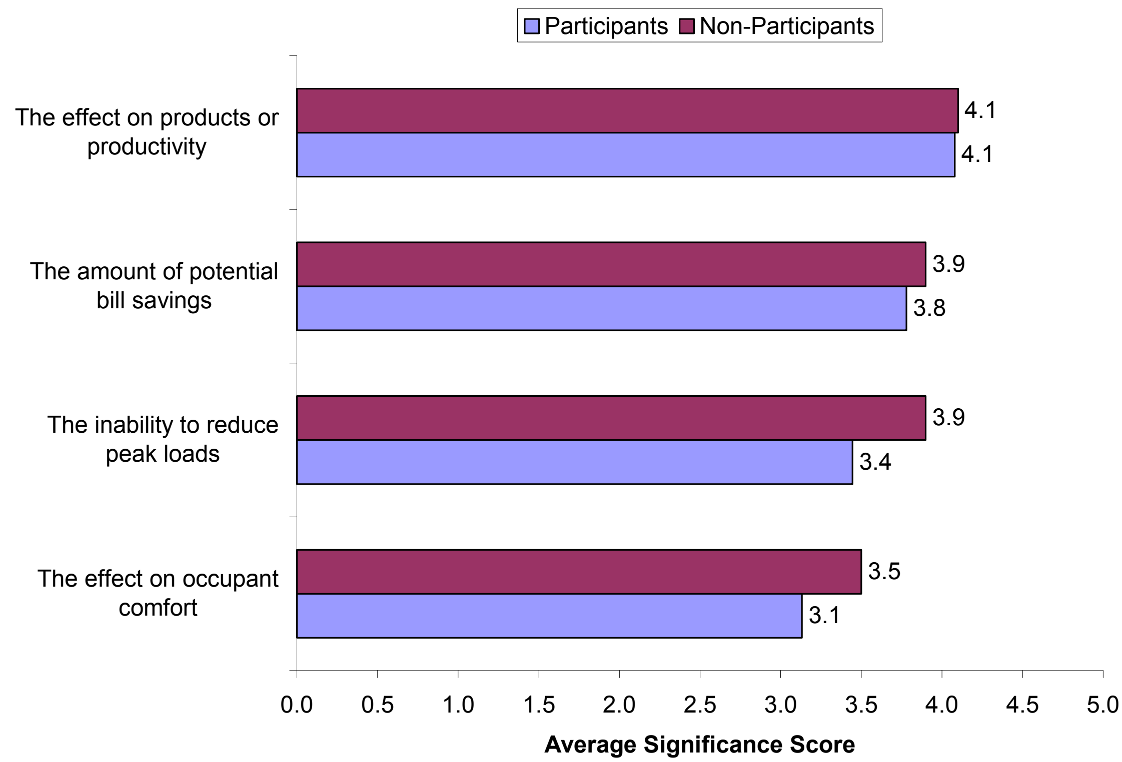
CPP and DBP participants were read four concerns that an organization might view as barriers to participation in DR programs or to implementing demand reduction actions. Respondents were asked to rank the significance of these four concerns to their organization on a 1 to 5 scale, where 5 means extremely significant and 1 means insignificant. The mean response for each of these concerns is provided in Exhibit 5-28 along with the specific means for the CPP and DBP participant populations surveyed.

Exhibit 5-28
Barriers to Participation in CPP and DBP Events



These same barrier questions were asked during the Quantitative Non-Participant survey that was conducted in March of this year to a population of non-participants that was representative of the entire eligible CPP and DBP population. Exhibit 5-29 compares the mean significance scores for these four barriers for the participant population to the non-participant population. These participant/non-participant results are compared further in Chapter 4 of this report.

Exhibit 5-29
Barriers to Participation in CPP and DBP Events – Participants versus Non-Participants

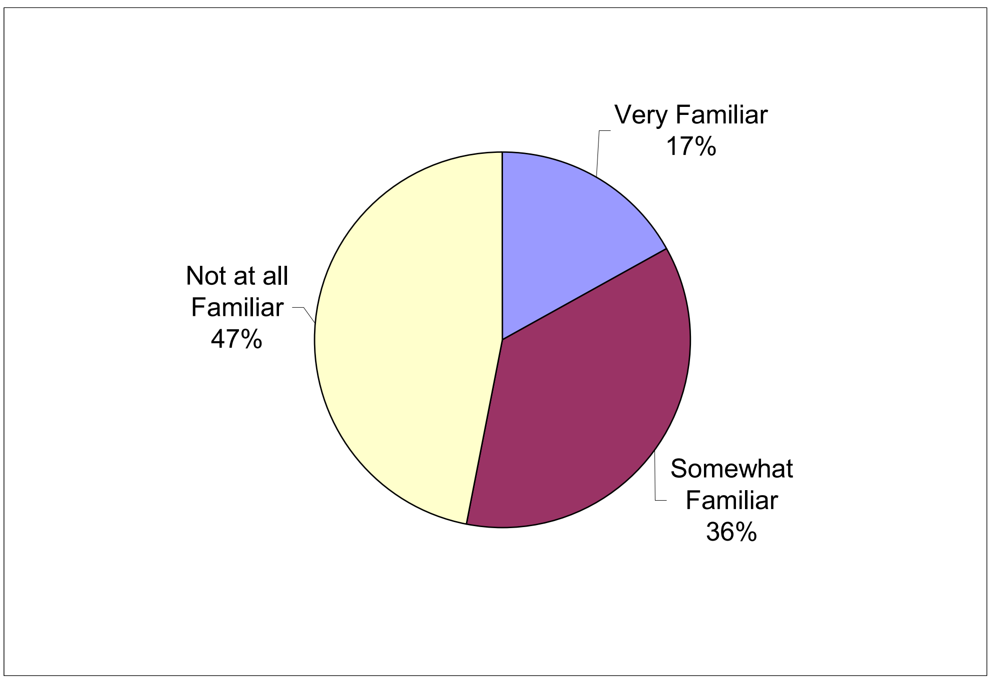


To evaluate the extent to which customers were prepared to participate in the programs – that is, how to receive and interpret notifications; how to submit bids for DBP; how to curtail load and evaluate performance – participants were asked how well prepared their organization was to manage the demand reductions called for by their utilities. Most respondents indicated they were either very well prepared (38 percent) or somewhat prepared (48 percent), however, 12 percent reported being not at all prepared. CPP participants were more likely to be well prepared than DBP participants (49 percent versus 35 percent, respectively), which is potentially due to the fact that they did not need to learn the bidding process to participate. Customers who reported they were somewhat or not at all prepared to participate offered "Have other priorities" and "Difficult for us to shed much load" as their top two reasons.

When asked to characterize the level of assistance they received in the development of load reduction options and strategies for their facility, most participants (70 percent) said they received as much support as needed. Twenty-one percent said they received some but not enough support, and 7 percent said they did not receive any support at all. The 30 percent who indicated they did not receive as much support as they needed were asked what additional support would have helped them be able to reduce their demand. The majority of the suggestions included specific instructions on how to reduce load, more information about how to use the system, and more warning before an event.[13]

All three of the IOUs offer a Technical Assistance incentive to their CPP and DBP program participants that pays for a portion of the cost of a professional audit to determine their facility's load reduction potential (up to $50 per kW reduced) if they agree to participate in one of the DR programs and demonstrate the load reduction (see Chapter 2 for description). When participants were asked about their familiarity with this incentive almost half of respondents (47 percent) indicated they were not at all aware of the incentive, as shown in Exhibit 5-30 below. Of those who were familiar with the incentive, one-quarter said they had taken advantage of the Technical Assistance incentive (18 participants). This response clearly indicates confusion among the participants regarding the incentive since, according to the utility program managers, no customers have taken advantage of this incentive.

Exhibit 5-30
Familiarity with Technical Assistance Incentive



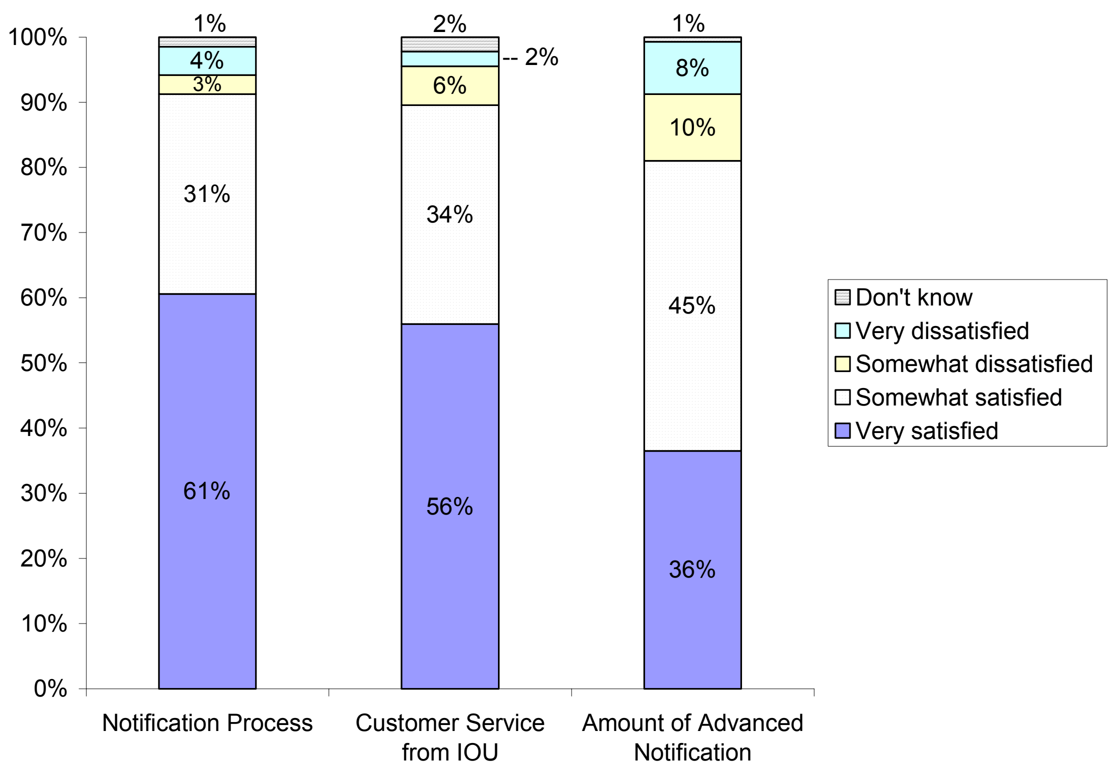
5-10 PROGRAM SATISFACTION

CPP and DBP respondents were asked a series of questions to rate their overall satisfaction with the DR program they participated in during the summer of 2004. A complete set of responses to these satisfaction questions, broken down by utility, customer size and business type, are provided in Appendix E. Additional discussion on this topic is provided as part of the CPP-DBP Process Evaluation (Chapter 8).

[13] Appendix Exhibit E-49 (Level of Assistance); Appendix Exhibit E-50 (Additional Support)

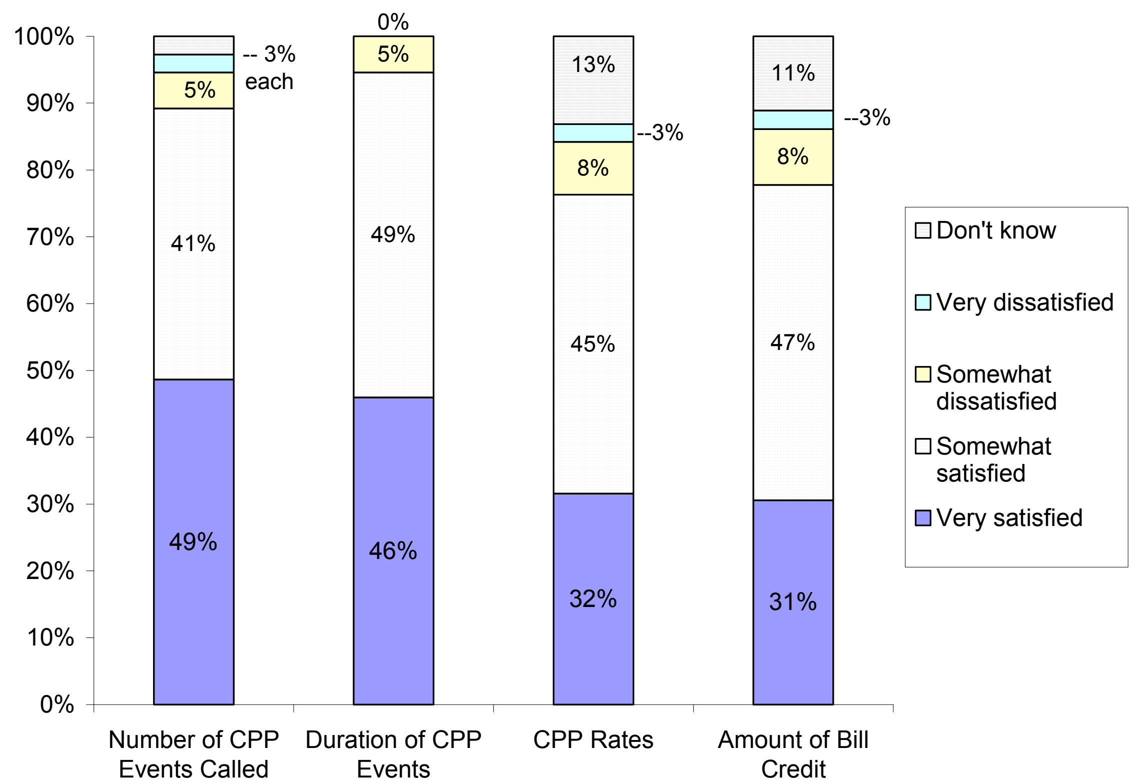
CPP and DBP Respondents were asked a series of questions about their satisfaction with various aspects of the demand response programs. As Exhibit 5-31 shows, overall, respondents were fairly satisfied with the notification process and customer service from their IOU (92 percent and 90 percent reporting very or somewhat satisfied, respectively). Very few respondents reported being somewhat or very dissatisfied in those two areas. Consistent with their responses to related survey questions, respondents reported being slightly less satisfied with the amount of advanced notification (81 percent were very or somewhat satisfied), demonstrating minor room for improvement in that aspect of the program.

Exhibit 5-31
CPP and DBP Participant Satisfaction with the Notification Process, the Customer Service Received and the Amount of Advanced Notification



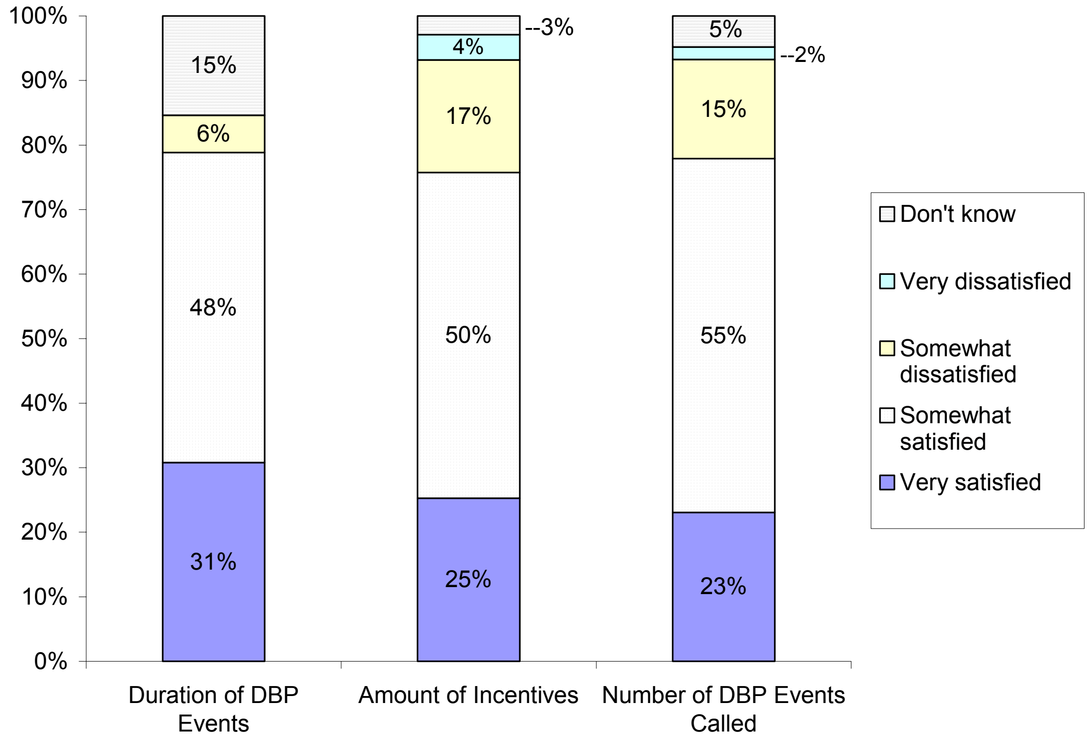
CPP and DBP participants were also asked to rank their satisfaction with the number of events called, the duration of the events, and the financial aspects of the program. As shown in Exhibit 5-32, CPP participants were fairly satisfied with the number of CPP events called and the duration of CPP events. Their satisfaction with the CPP rates and the amount of bill credit received was slightly lower, though the majority of this decline could be attributable to the increase in participants that said they were unsure of their level of satisfaction (13 percent and 11 percent reported 'Don't Know' as their level of satisfaction with the CPP rates and amount of bill credit received).

Exhibit 5-32
CPP Participants' Event and Rate Satisfaction



DBP participants reported lower satisfaction levels than CPP participants in all categories. (Again, it is important to remember while reviewing these results that for all of the utilities these DBP satisfaction ratings are based solely upon day-of test or emergency-triggered events, as no day-ahead events were called during the summer of 2004.) As shown in Exhibit 5-33, 79 percent of DBP participants reported being satisfied with the duration of the DBP events, while an additional 15 percent were unsure of their satisfaction with this aspect of the program. In the other categories, 21 percent of DBP participants surveyed reported being somewhat or very dissatisfied with the amount of incentives paid and 17 percent reported these feelings with regards to the number of DBP events called.

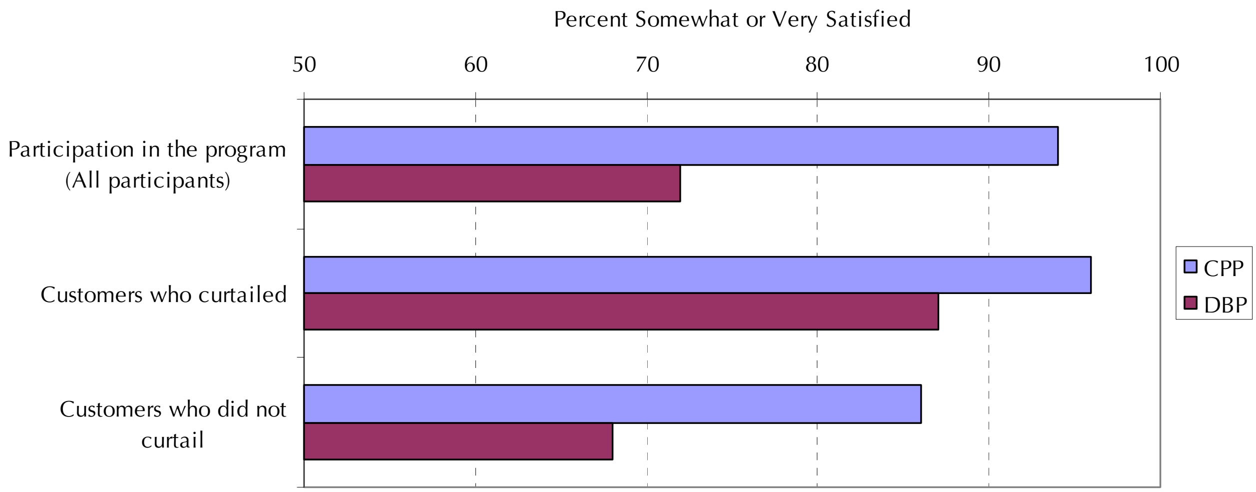
Exhibit 5-33
DBP Participants' Event and Incentive Satisfaction



Looking at satisfaction with the incentives paid for DBP participants revealed little difference between the perceptions of bidders and non-bidders (with PG&E excluded since they did not place bids for the one DBP event this past summer). Among bidders, 78 percent said they were somewhat or very satisfied with the program incentives, compared to 82 percent for non-bidders.

CPP and DBP participants were also asked to rank their overall satisfaction with the 2004 DR programs as a whole. Exhibit 5-34 shows the percentage of CPP and DBP participants who were somewhat or very satisfied with their overall participation in the program along with these rankings broken down by whether or not they took curtailment actions this past summer. As this exhibit shows, CPP participants indicated much higher levels of satisfaction with the program as a whole, and, for both CPP and DBP programs, customers who took curtailment actions this summer reported higher levels of satisfaction than those who did not take actions.

Exhibit 5-34
Participant Satisfaction with their Overall Participation in the CPP or DBP Program



All CPP and DBP participants were asked if they had any suggestions for improving the DR programs regardless of their satisfaction. Half of the CPP participants reported having no suggestions, while others recommended more advanced notice and increased incentives, among other responses as shown in Exhibit 5-35.

Exhibit 5-35
Suggestions for Improving the CPP Program

ES17_CPP. Do you have any suggestions for improving the CPP program?	Total
Nothing	51%
Want more advanced notice	14%
Increase incentives	8%
More technical assistance	5%
Give real time data of demand during event	5%
Improve website	5%
Other	16%
N	37

* N is the number of respondents.

Sixty-one percent of DBP participants reported having no suggestions for program improvement. Those offering suggestions for DBP gave similar improvements to what was suggested for CPP (more advanced warning before an event and increased incentives). These suggestions, as well as others, are presented in Exhibit 5-36.

Exhibit 5-36
Suggestions for Improving the DBP Program

ES22_DBP. Do you have any suggestions for improving the DBP program?	Total
Nothing	61%
Give more warning before an event	18%
Increase incentives	10%
Follow up after event	2%
Notify more than one person	1%
Reduce load shed requirement	1%
More technical assistance	1%
Other	11%
N	104

* N is the number of respondents.

5.11 LIKELIHOOD OF FURTHER PARTICIPATION

An additional means of determining customers' satisfaction with the CPP and DBP programs is to determine their intentions for future participation. Questions were asked regarding their likelihood of bidding or taking DR actions in future events as well as their intentions for next summer. A complete set of responses to these satisfaction questions, broken down by utility, customer size, and business type, are provided in Appendix E. Additional discussion on this topic is provided as part of the CPP-DBP Process Evaluation (Chapter 8).

During each of the Post-Event surveys CPP and DBP participants were asked about their likelihood of placing bids or taking demand reduction actions in future events during the summer. Consistent with previous finding, CPP participants were much more likely to expect to take demand reduction actions for future events than DBP participants overall. DBP participants who had submitted bids, however, had an even higher percentage that were very or somewhat likely to take action than did CPP participants (88 percent versus 84 percent). The complete results are shown in Exhibit 5-37.

Exhibit 5-37
Likelihood of Future DR Actions in CPP and DBP Events

How likely are you to bid (DBP) / take demand reduction actions (CPP) for future events?	CPP All	DBP All	DBP (No PG&E)	DBP - Bid	DBP - No Bid
Very likely	67%	38%	37%	65%	26%
Somewhat likely	17%	34%	33%	23%	37%
Neither likely nor unlikely	4%	4%	3%	0%	4%
Somewhat unlikely	7%	16%	19%	8%	24%
Not at all likely	4%	8%	7%	4%	9%
N	46	119	94	26	68

Most CPP participants (86 percent) said they plan to participate in the CPP program next summer. Although no one said they do not plan to participate next summer, 14 percent said they were not yet sure. When asked why they plan to participate next summer, respondents gave reasons such as "Save money," "Good corporate citizen," and "Not difficult to reduce load."[14] Participation plans for CPP participants are provided in Exhibit 5-38.

Exhibit 5-38
Planning to Participate in CPP Next Summer

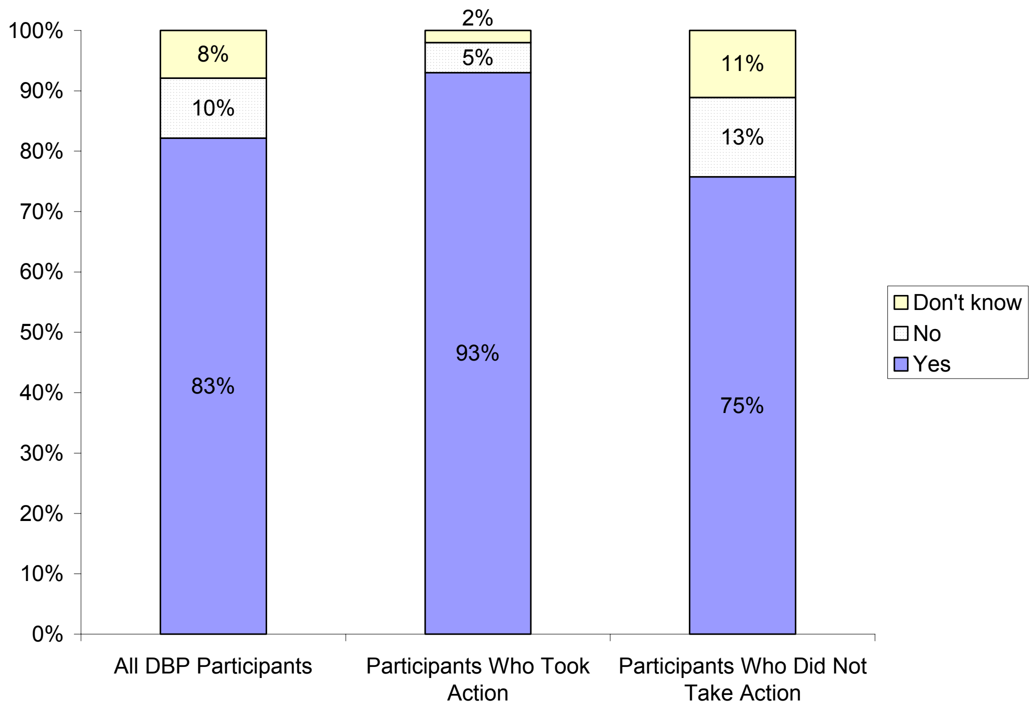
ES18_CPP. Do you plan to participate in the CPP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	86%	100%	83%	71%	100%	100%	69%	92%	81%	100%	93%
Don't know	14%	0%	17%	29%	0%	0%	31%	8%	19%	0%	7%
N	37	7	18	7	4	7	13	13	21	2	14

As Exhibit 5-39 shows, most DBP participants (83 percent) also stated their intention to participate in the DBP program next summer. Ten percent said they do not plan to participate and another 8 percent reported they were unsure about their future plans. In an effort to determine whether or not participation in previous DBP events had and impact on future participation plans, this question was broken down by whether the customer had curtailed for previous events. The results showed that participants who took demand reduction actions were more likely to say that they would participate in the DBP program next year than those who had not taken DR actions. Those who planned to participate next summer gave reasons such as "Save money," "Good corporate citizen," and "Good program." Those who did not

[14] Appendix Exhibit E-77 (CPP Plan to Participate); Appendix Exhibit E-78 (CPP Reasons for Participation)

plan to participate gave reasons such as "Not happy with the program" and "Did not get much out of the program."[15]

Exhibit 5-39
Plan to Participate in DBP Program Next Summer



Customers who planned to participate in the CPP program next summer were asked whether they thought their demand reductions would increase, decrease, or stay about the same. Most CPP participants (79 percent) believed their demand reduction would remain the same, although 15 percent said they believed their demand reduction would increase. For DBP, two-thirds of customers who plan to participate next summer believe their demand reductions will remain the same. However, 27 percent of DBP participants reported they expect their demand reduction to increase next summer. A comparison of the expected demand reductions for next summer can be seen in Exhibit 5-40 below.

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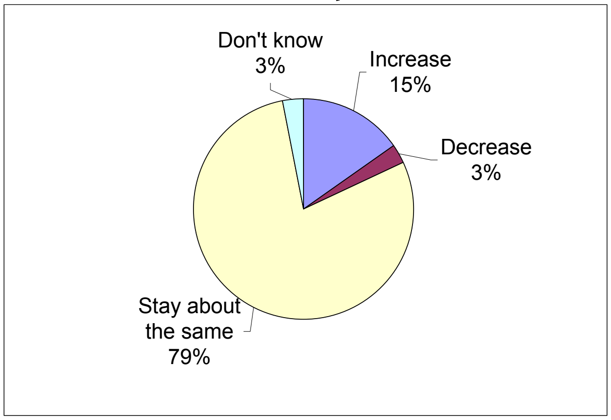
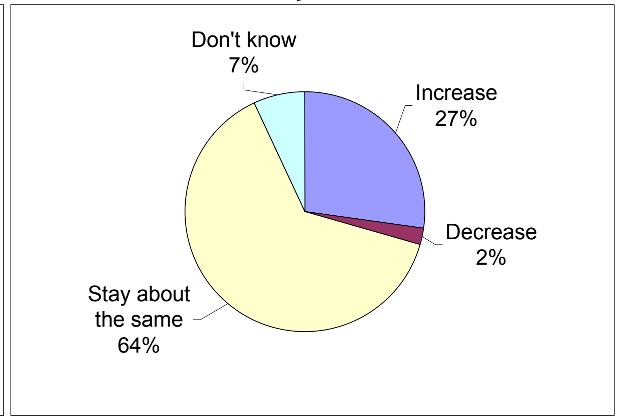
15 Appendix Exhibit E-89 (DBP Reasons for Participation)

Exhibit 5-40
Expected Change in Demand Reduction Next Summer

CPP Participants (N=33)

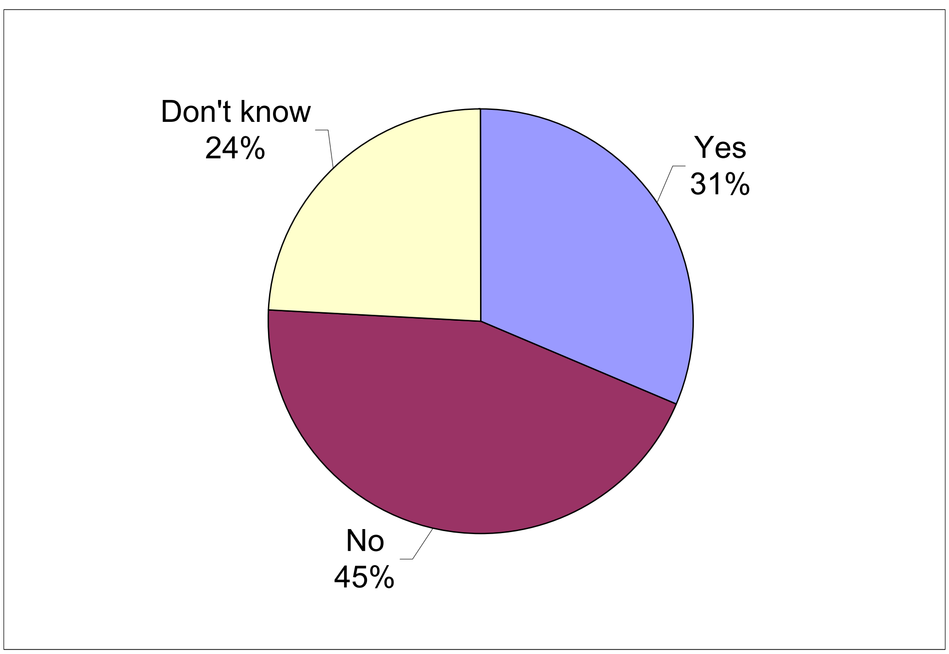


DBP Participants (N=88)



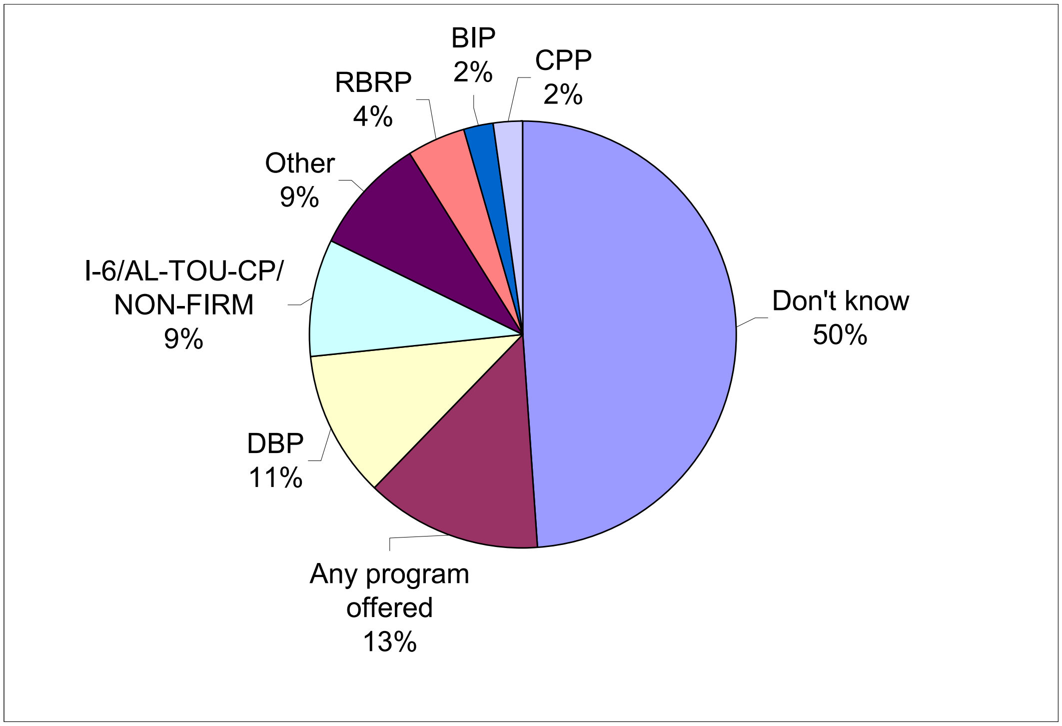
Participants were also asked about their plans to participate in other demand response programs or tariffs offered by their utility. Almost a third of participants (31percent) said they plan to participate in another demand response program or tariff, as shown in Exhibit 5-41.

Exhibit 5-41
Plan to Participate in Another Demand Response Program



Those respondents who indicated thy planned to participate in another demand response program listed programs such as DBP, CPP, I-6, RBRP, and BIP, as seen in Exhibit 5-42. Several respondents said they would participate in any demand response program that was offered to them.

Exhibit 5-42
Other Demand Response Programs Likely to Participate In

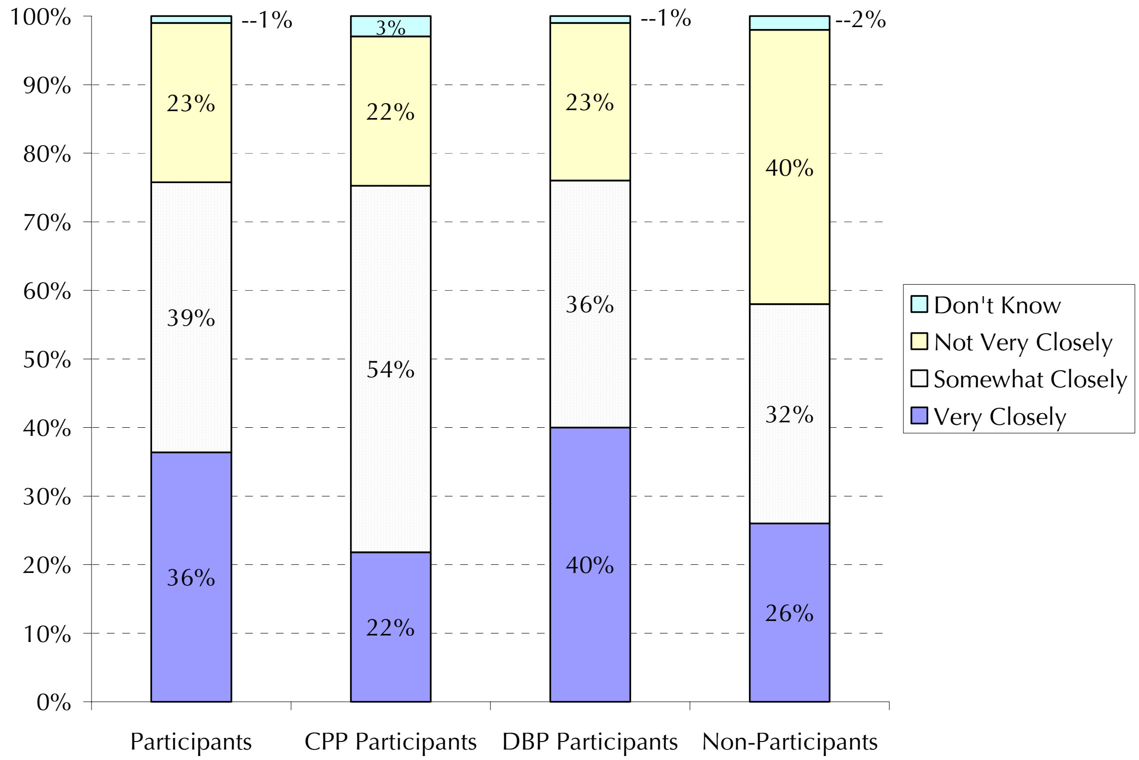


5.12 GENERAL MARKET PERCEPTIONS

A few questions were asked of all participants to gauge their organizations' attitudes towards electricity markets and prices. These same questions were asked of non-participants in March of this year as part of the Quantitative Non-Participant survey. A full statistical analysis was performed using these questions to determine if the responses to these questions indicated a difference in characteristics that make one organization be more likely to participate in the DR than another. This analysis is presented in the end of Chapter 4. In addition, a complete set of responses to these satisfaction questions, broken down by utility, customer size, and business type, are provided in Appendix E.

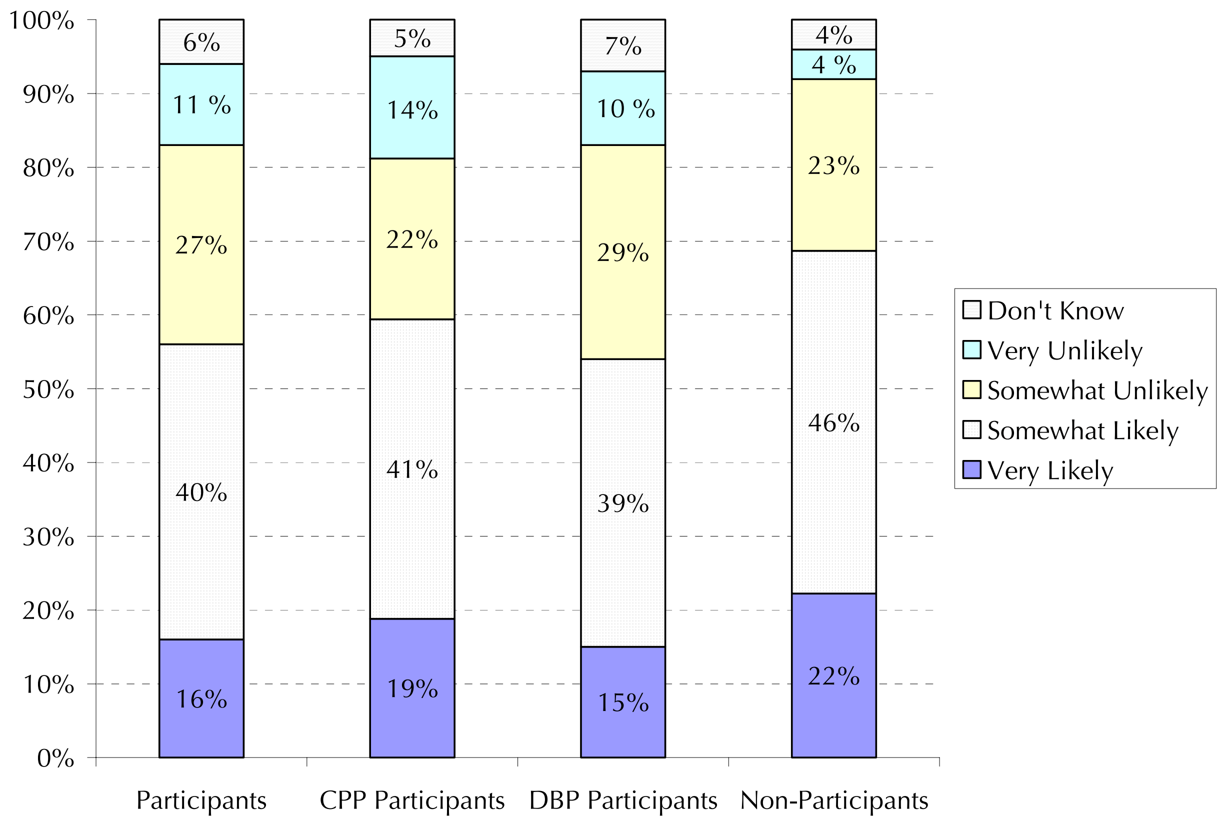
When asked how closely their organization monitored and analyzed electricity markets and prices, 36 percent said very closely, 39 percent said somewhat closely, and 23 percent said not very closely. As shown in Exhibit 5-43 below, customers who signed up for the DBP program were more likely to pay closer attention than those who signed up for CPP. Overall, non-participants were also less likely than participants to pay very close attention.

Exhibit 5-43
Closeness of Monitoring Electricity Markets and Prices



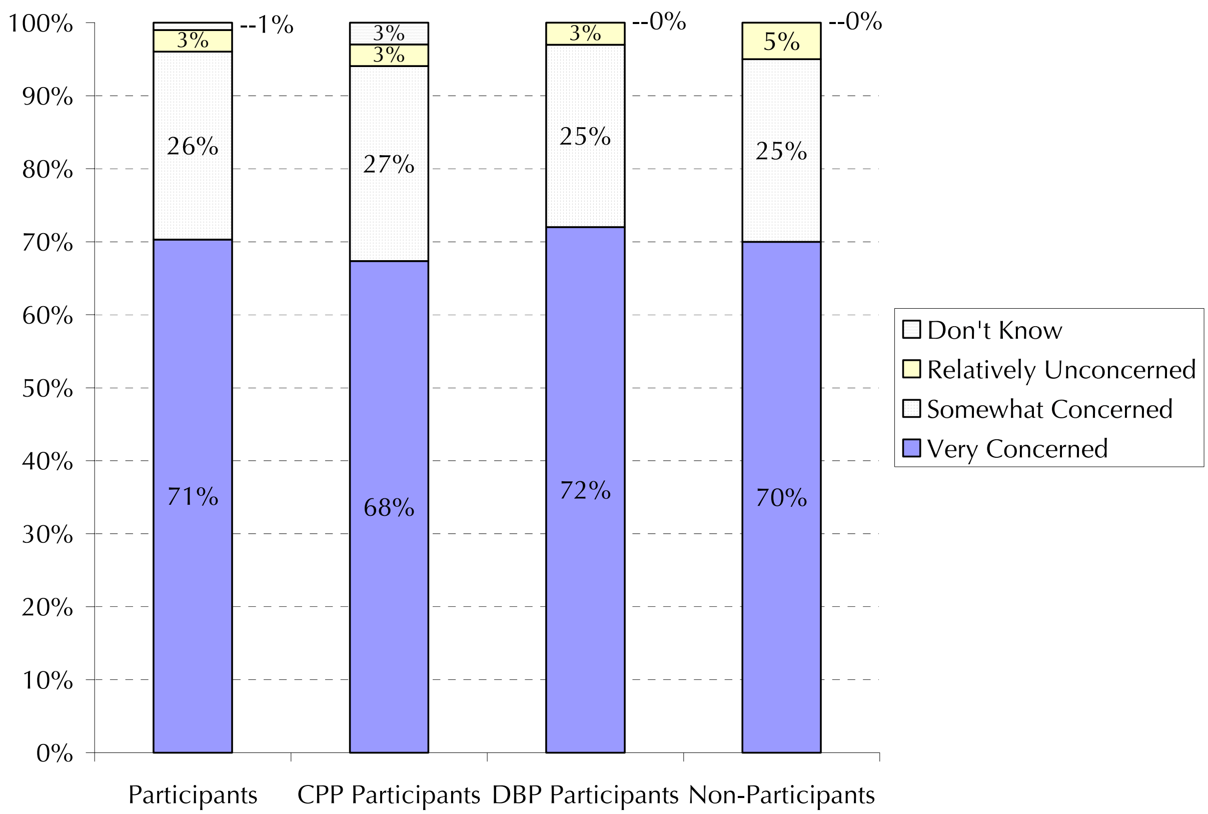
Participants and non-participants were also asked how likely they thought it was that California's power supplies would be inadequate to meet expected power demand over the next three years. Over 56 percent of participants indicated that power supplies were very likely or somewhat likely to be inadequate compared to 68 percent of non-participants. Exhibit 5-44 below provides a full illustration of the responses for participants overall, CPP participants, DBP participants and non-participants.

Exhibit 5-44
Likelihood of California's Power Supply Being Inadequate Over Next 3 Years



When participants and non-participants were asked how concerned their organization was about energy costs relative to other costs of running their business, 71 percent said very concerned, 26 percent said somewhat concerned, and only 3 percent said relatively unconcerned.[16] Exhibit 5-45 below provides the distribution of levels of concern for participants overall, CPP participants, DBP participants and non-participants. It is interesting to note how similar the responses are for each of the distinct populations.

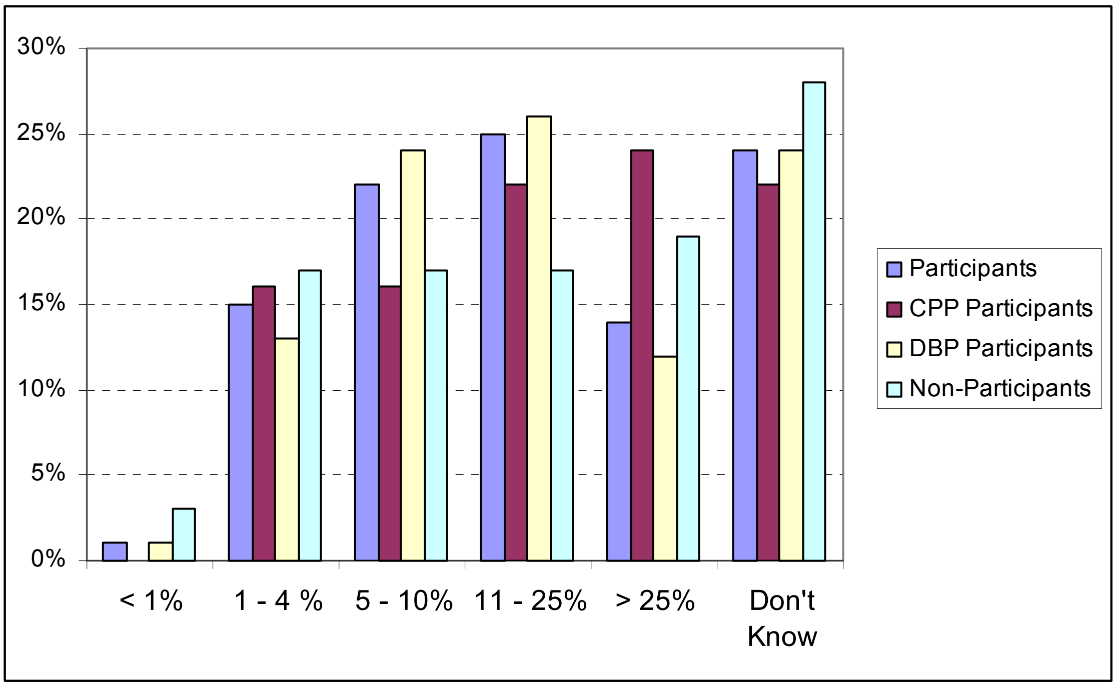
Exhibit 5-45
Concern About Energy Costs Compared to Other Business Expenses



[16] Appendix Exhibit E-96 (Monitor Electricity Markets); Appendix Exhibit E-97 (California's Power Supplies); Appendix Exhibit E-98 (Concern Over Energy Costs)

Both participants and non-participants were asked to estimate what percent of their organizations' total annual operating costs is attributed to energy costs. As shown in 5-46, the distribution of energy costs is quite similar for parts and non-parts. Only 14 percent of participants thought their energy costs represented more than 25 percent of operating costs. And almost half (47 percent) believed energy costs fell between 5 and 25 percent of total their annual operating costs.[17] It was interesting to note that a larger percentage of non-participants were unsure what percent of their operating budget was spent on energy (27 percent versus 22 percent), which may result in their organizations being less likely to participate in the DR programs in order to reduce their energy bill.

Exhibit 5-46
Self-Reported Percentage of Organizations Operating Costs Spent on Energy



Participants and non-participants were also asked what end use was the largest in terms of electrical consumption for their organization. For all populations (participants and non-participants) HVAC was reported to be the largest end use, followed by continuous processing, and refrigeration. When asked about second largest end use, lighting, processing, and HVAC were at the top of the list. The complete distribution of the self-reported largest end-use are shown in Exhibit 5-47.

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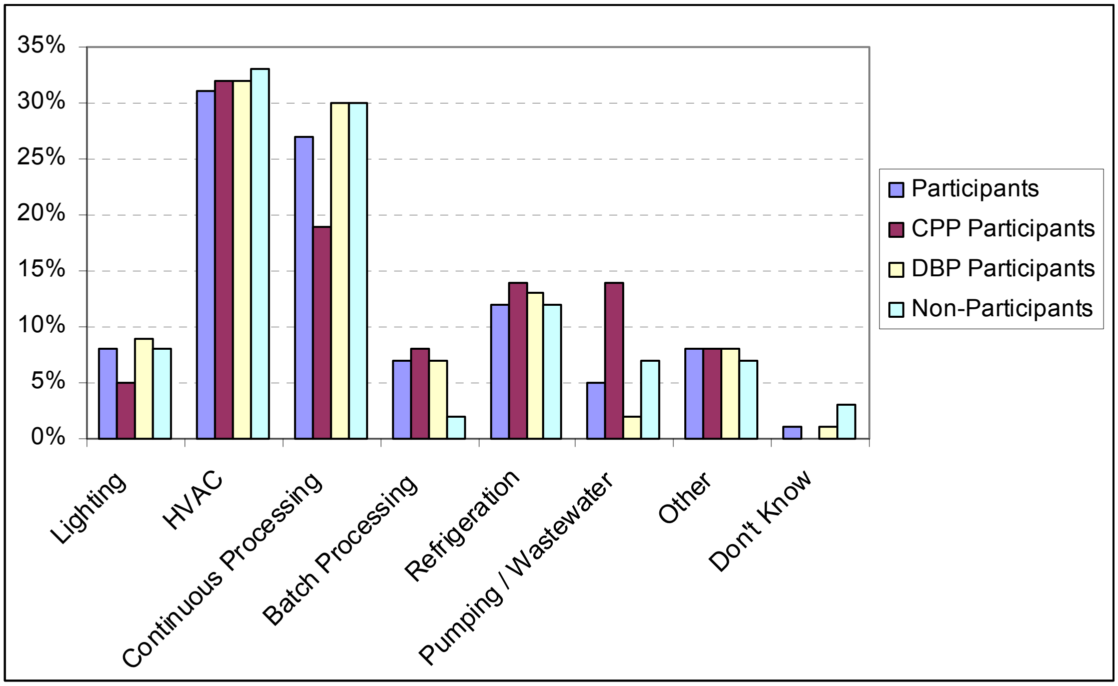
[17] Appendix Exhibit E-99 (Energy Costs)

Exhibit 5-47
Largest End Use in Terms of Electrical Consumption



6. BASELINE ASSESSMENT

Assessing Load Shape Change is viewed as a key analytic task in the overall Demand Response evaluation since a main goal of the DR programs is to shift load in response to prices or trigger events. Additionally, for the DBP program, a baseline for billing is needed in that the "actual demand reduction" as defined in the DBP tariff must be calculated for payments. Given that an impact calculation must be made for payment under this program and that a process has been set up to calculate this impact using a method similar to that employed by DR programs elsewhere, one research question concerns how accurate and fair the tariff-based impact calculation is to both parties (the utility and customer). Developing a calculation method for making program payments may consider a number of factors in addition to the pure accuracy of the method. In addition, the method should be relatively transparent and easily understood by the participant, and not be so complex that it delays the payment calculation. Also, there is the research objective of obtaining the most accurate estimate of load impacts possible for the benefit/cost analysis of this program – with payments to customers being one component of program costs.

To address this issue, this section contains a discussion and analysis of three basic methodologies for estimating baselines in DR impact assessment. The findings from this section can be used to assess whether the baseline method currently used for DBP settlement is satisfactory. In addition, the results from this section are used to select the best baseline method to use to estimate the overall DR program impacts, which we present in Chapter 7 of this report.

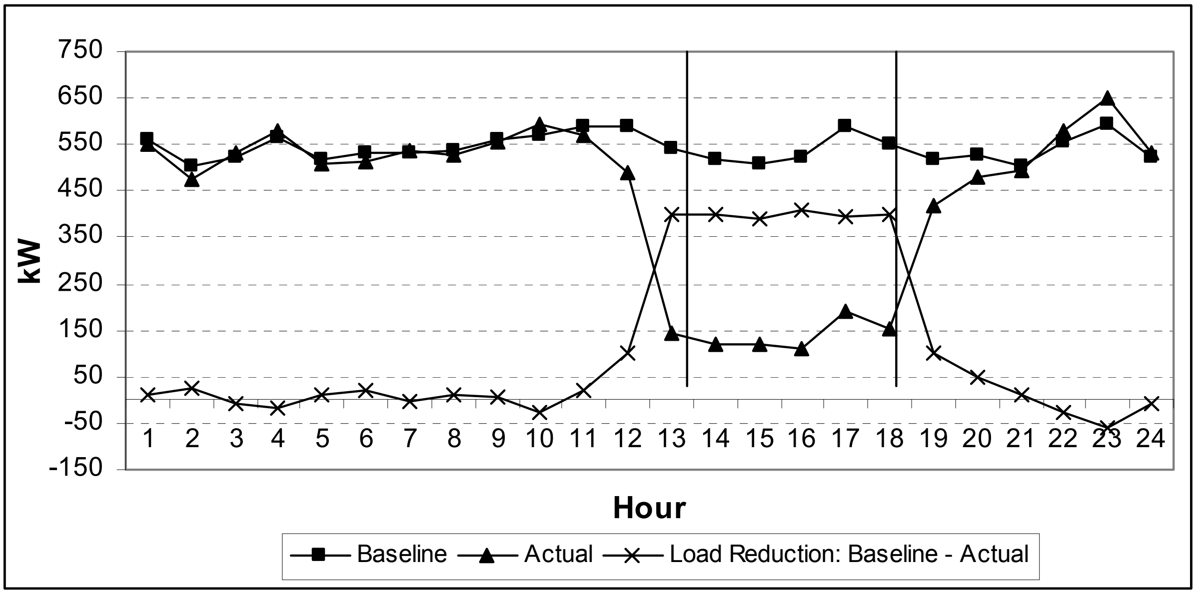
This Chapter summarizes our analysis of baseline load shape estimation methods. Additional results and documentation are provided in Baseline Appendix F.

6.1 BASELINE CALCULATIONS

Demand Response Baselines

One method of determining the impact of a demand response program event is to calculate a *demand response baseline* for each participating account for the given event day. A baseline provides an hourly estimate of the load shape of an account if no curtailment activities were to occur. The impact of an individual account for a particular demand response event can be estimated by calculating the difference between their baseline and their actual load for the given event day. An example of a demand response baseline, actual load and estimated load reduction for a hypothetical customer is provided in Exhibit 6-1.

Exhibit 6-1
Illustration of Demand Response Baseline, Actual Load and Estimated Load Reduction



Both the CPP and DBP programs use demand response baselines to estimate the load reduction each participating account contributes to the overall impact of the programs. Additionally, the DBP program uses the baseline to determine the appropriate payment amount for settlement of incentive payment with the customer. The CPP program does not use the baseline for settlement, rather under the CPP tariff, customers' bills are based on their energy use during the peak, critical-peak and off-peak time periods. Numerous methodologies can and have been employed to calculate demand response baselines. A subset of these methodologies was selected for inclusion in this baseline assessment and will be further explained and evaluated in the remainder of this chapter.

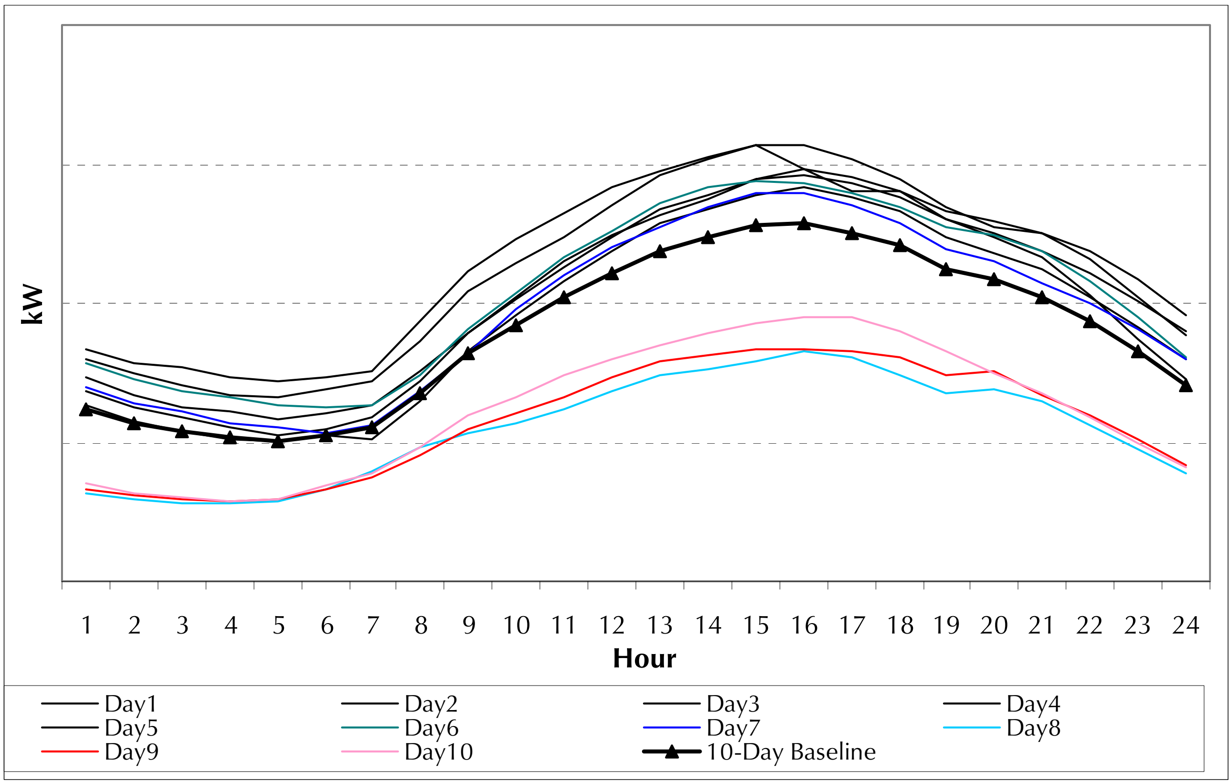
Distinct Baseline Methodologies Evaluated

The analysis of customer baselines began by identifying and selecting a set of baseline methodologies that included the methods used for settlement in the 2004 CPP and DBP programs, as well as several distinct alternatives that could be used to compare and contrast to the current baseline calculations. The alternative baselines were selected based on a literature review of work that had previously been conducted examining alternative baseline methodologies, recommendations from WG2 committee members, and a review of baselines that are currently employed for other large customer programs at one or more of the California utilities.

3-Day Baseline

The current baseline methodology that is being used for settlement at each of the three utilities for the CPP and DBP programs is referred to as the ***3-Day Baseline***. This baseline is calculated by first selecting a series of days that represent the most recent 10 similar days that occurred prior to the event day. Similar days exclude weekends, holidays and any additional days during which a customer was paid to curtail their load. From this series of 10 similar days, the three days with the highest overall load during the curtailment hours were selected and the load for each hour of these three days was averaged (by hour) to calculate an hourly 3-Day baseline estimate. The 3-Day baselines differ for CPP and DBP due to the fact that the curtailment hours for these programs differ (see analysis hours section below for details). Exhibit 6-2 provides an example of a 3-Day baseline, along with the 10 similar days used to calculate this baseline (the 3 highest days are in bold).

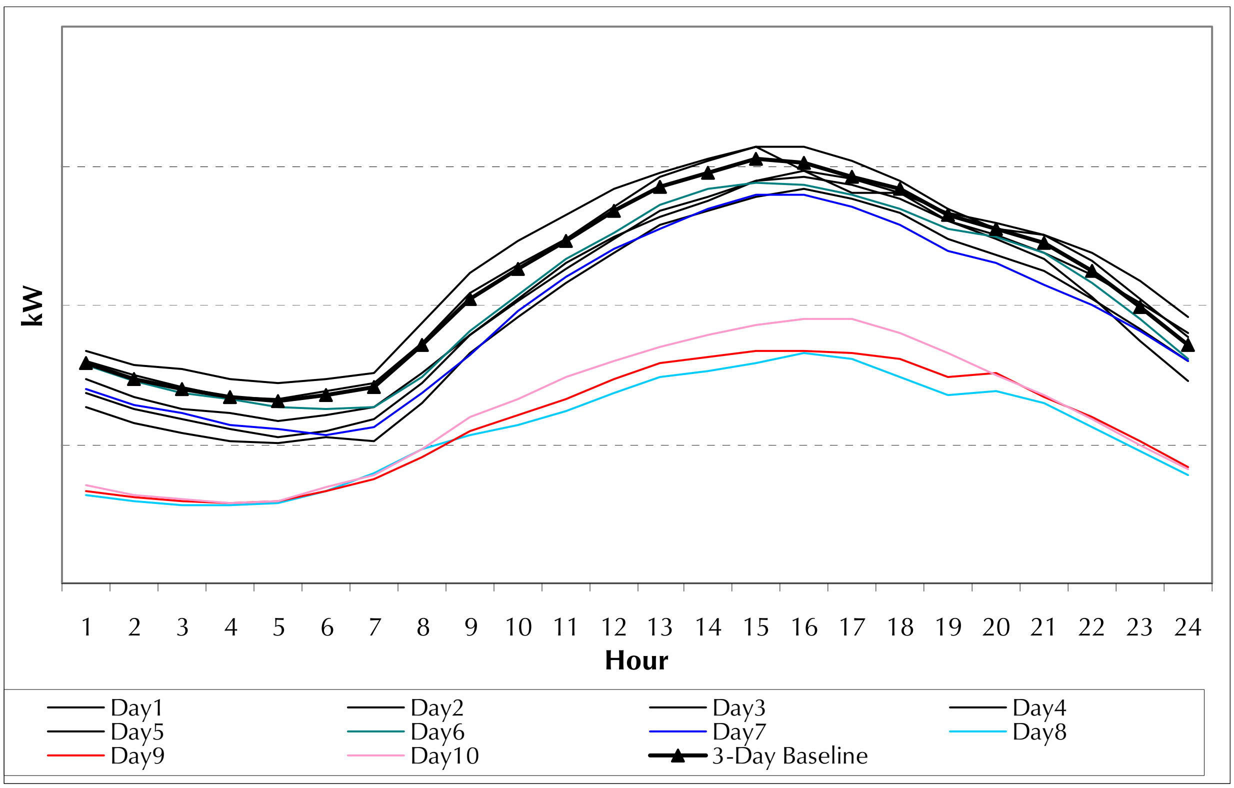
Exhibit 6-2
Illustration of 3-Day Baseline
Calculated By Averaging Over Highest 3 Days From Most Recent 10 Similar Days



10-Day Baseline

The first alternative baseline methodology evaluated was for the ***10-Day Baseline***. This baseline is similar to the 3-Day baseline in that it also selects a series of the last 10 similar days. However, as opposed to selecting the three highest days from the last 10 days, this approach calculates the baseline for each hour by averaging the hourly load over all of the last 10 similar days. Because the 10-Day baseline is not dependant on the curtailment hours of the program, the 10-Day baselines for CPP and DBP are identical. However, both are calculated and included in the analysis since the hours for which the programs are operational are different and thus the overall performance of the baselines over the curtailment period can vary. Exhibit 6-3 provides an example of a 10-Day baseline along with the 10 days used to calculate this baseline.

Exhibit 6-3
Illustration of 10-Day Baseline Calculated By Averaging Over Last 10 Similar Days



10-Day Adjusted Baseline

The second alternative baseline methodology evaluated was for a ***10-Day Adjusted Baseline***. The 10-Day adjusted baseline is calculated by applying a scalar adjustment to the 10-Day baseline (as described above) based on a series of calibration hours. This baseline is similar to the baseline currently being used for settlement in the California Power Authority's Demand

Reserves Partnership (CPA-DRP) program[1] and the Optional Binding Mandatory Curtailment (OBMC) program.[2] The scalar adjustment factor was calculated by computing the ratio of the average load over three calibration hours to the average load for the same three hours from the last 10 similar days. Multiplying each hour of the 10-Day baseline by the scalar adjustment factor gives us the 10-Day Adjusted baseline, which is essentially the 10-Day baseline scaled to the customer's same-day operating level for the calibration hours.

$$\textit{10-Day Adjusted Baseline} = \textbf{Calibration Ratio} * \textit{10-Day Baseline}$$

where,

$$\textbf{Calibration Ratio} = \frac{\text{Average Load during Calibration Hours}}{\text{Average Load during same hours from the last 10 similar days}}$$

Exhibit 6-4 below shows an example of how the calibration ratio is calculated for a hypothetical customer and provides the resulting 10-Day Adjusted baseline.

Exhibit 6-4
Calibration Ratio Calculation

	Calibration Hours						Event Hours			
Hour Beginning	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
10-Day Baseline	6.2	6.6	7.2	7.3	8.1	9.2	8.9	8.7	7.2	7.5
Event Day Load	5.3	5.4	6.5	7.3	8.3	7.8	5.2	4.9	5.2	5.5

$$\textbf{Calibration Ratio} = \frac{\mathbf{5.3 + 5.4 + 6.5}}{\mathbf{6.2 + 6.6 + 7.2}} = \frac{\mathbf{17.2}}{\mathbf{20}} = \mathbf{0.86}$$

	Calibration Hours						Event Hours			
Hour Beginning	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
10-Day Baseline	6.2	6.6	7.2	7.3	8.1	9.2	8.9	8.7	7.2	7.5
Calibration Ratio	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
10-Day Adjusted Baseline	5.3	5.7	6.2	6.3	7.0	7.9	7.7	7.5	6.2	6.5

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[1] The CPA-DRP program is a day-of program where notification is provided to customers an hour before curtailment is to begin. The baseline used for the CPA-DRP program also uses three hours prior to the event notification as calibration hours, however, it applies this adjustment to what they refer to as a *Mid-8 Baseline* (where the highest and the lowest values for each hour from the 10 days selected are excluded from the baseline prior to the adjustment, thus, leaving 8 days).

[2] Similar to the CPA-DRP program, the OBMC program is a day-of program where notification is provided to customers an hour before curtailment is to begin. The baseline used for the OBMC program uses the four hours prior to the event notification as calibration hours and applies this to a similar 10-Day baseline.

The calibration hours used for this analysis were the three hours prior to the event notification. Implementation of such an adjustment for settlement and evaluation purposes can be problematic for programs such as CPP and DBP that are in some cases announced on prior days. In such situations, selecting the calibration hours from the day the notification of the event is delivered may limit the power of the adjustment, however, selecting calibration hours on the day of the event (after the notification has been given) increases the likelihood of the baseline being gamed or biased by an intentional increase in consumption during the calibration hours. This would cause the baseline to be overstated and result in a higher estimated load reduction and compensation payment. For this analysis two distinct time periods were selected as calibration hours, the first for day-of events and the second for day-ahead events. For day-of DBP events, each utility begins to notify customers about the event at approximately 12 p.m. on the day the event is to occur. For this reason the hours of 9 a.m. to 12 p.m. were used as the calibration hours for day-of events. For both CPP and DBP day-ahead events, the utilities begin the event notification process at 3 p.m. on the weekday prior to the day the event is to occur (which would be Friday for a Monday event). Thus for day-ahead events the hours of 12 p.m. – 3 p.m. on the weekday prior to the event day were used as the calibration hours. These hours were also used for SCE CPP events despite their pilot 2-day advanced notification process. For CPA-DRP the calibration hours are the three hours prior to the event notification.

Because the DBP program can be called on a prior-day or same-day basis, two 10-Day adjusted baselines were calculated for DBP using distinct sets of calibration hours. The CPP program can only be called on a prior-day basis and thus only one adjusted baseline was calculated for CPP (since the same-day load may be affected by intentional actions such as pre-cooling). Exhibit 6-5 shows the hours used for the two calibration adjustments for the CPP and DBP baselines for each of the utilities.

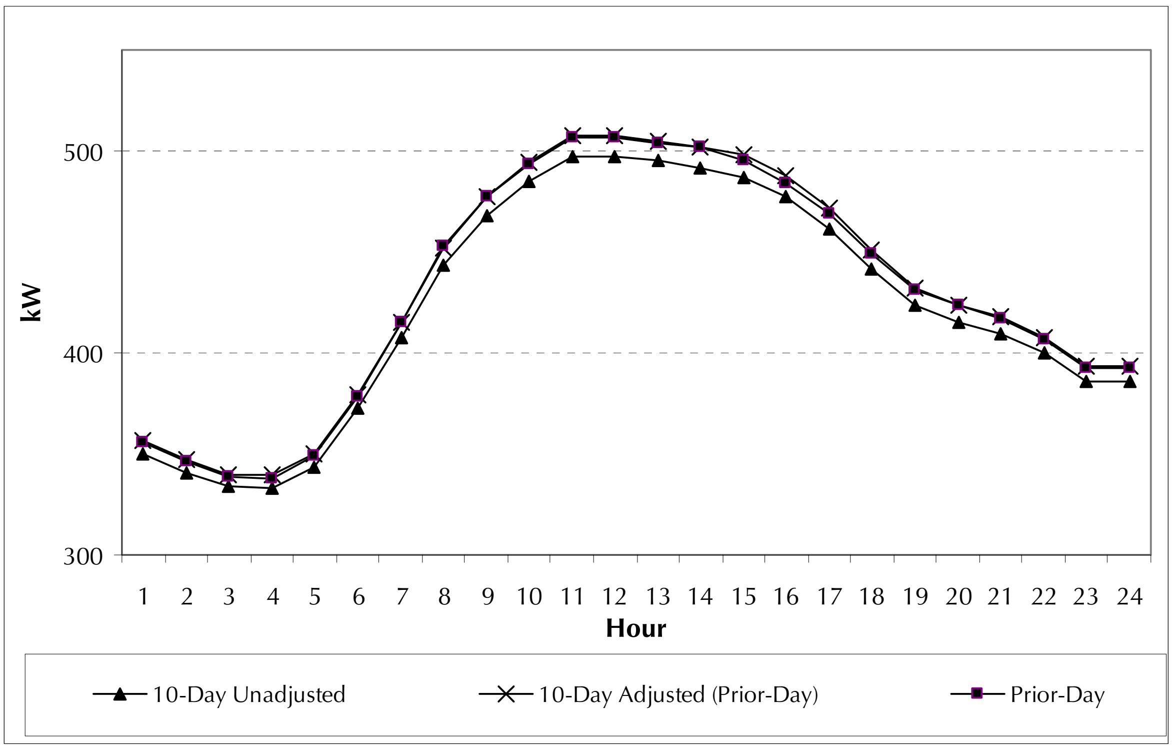
Exhibit 6-5
Hours Used for the Calibration Adjustment for the CPP and DBP 10-Day Adjusted Baselines

Program	Baseline Type	Adjustment Type	Calibration Hours
CPP	10-Day	Prior-Day	12pm - 3pm
DBP	10-Day	Prior-Day	12pm - 3pm
		Same-Day	9am - 12pm

A variety of problems can occur when calculating calibration adjustments that must be dealt with in order to keep the adjustments from unrealistically skewing the baselines. These problems typically occur when either the numerator or the denominator of the calibration ratio are zero, missing or less than one. A numerator of zero, missing or less than one causes the ratio to be extremely small or to be equal to zero. A denominator of zero or missing results in an error due to a division by zero and a denominator of less than one cause the ratio to be unrealistically large. To deal with these issues a series of rules were implemented to keep the ratios in check. The first rule implemented applied to situations where the denominator (the average load during the calibration hours over the last 10 similar days) was zero, missing or less than one. In these situations the calibration ratio was set equal to one so that the 10-Day adjusted baseline remains equal to the 10-Day non-adjusted baseline. A second rule implemented set upper and lower bounds on the calibration adjustments. The upper bound was set at a value of 2.0 and the lower bound was set at 0.5 thus ensuring that the 10-Day adjusted baseline would never be more than double or less than half of the 10-Day non-adjusted baseline.

Exhibit 6-6 provides an example of a hypothetical 10-Day adjusted baseline (using a prior-day adjustment) along with the corresponding 10-Day baseline and the load from the prior day (from which the calibration hours were selected).

Exhibit 6-6
10-Day Adjusted Baseline (Prior Day), 10-Day Non-Adjusted Baseline and Previous Day Load Used for Calibration Hours

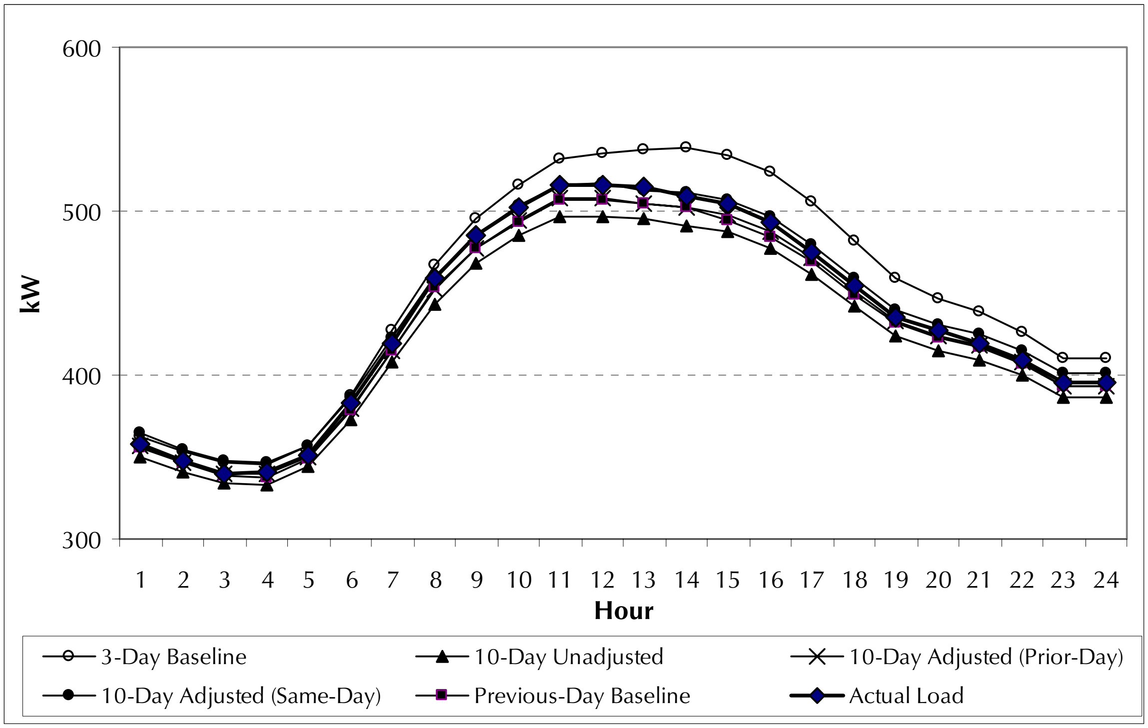


Prior Day Baseline

The third and final alternative baseline methodology evaluated was for a ***Prior Day Baseline***. The Prior day baseline simply uses the most recent "similar" day as a proxy for the subsequent day's baseline.

Exhibit 6-7 displays an example of the four distinct baseline methods being evaluated.

Exhibit 6-7
Illustration of All Baseline Methods Being Evaluated



Analysis Days Selected

The various baseline methodologies were evaluated over a series of days between July 1, 2003 and August 31, 2003. The days selected varied between utilities and were selected based upon the utility's system load data during this period (downloaded from oasis.caiso.com). The days selected for analysis fell into one or more of the following three "day type" classifications:

- **High load days** – The high load days represented the most likely potential event day (days with high system load and/or days falling at the end of a heat storm).
- **Low load days** – The low load days represent a potential "test" or distribution system emergency event day.
- **Consecutive high load days** – The consecutive load days were selected from a series of high load days that fell back to back. These days were selected to represent the possibility of a heat storm in which the events may be called consecutively.

Selecting baseline analysis days from each of the different "day type" classifications allows for a comparison of the distinct baseline methodologies to be made under different event day scenarios.

Exhibits 6-8 through 6-10 illustrate the system load for the three utilities for July and August 2003. The high demand analysis days selected for each utility are circled and listed in the Exhibit title.

Exhibit 6-8
PG&E System Load July and August 2003
High Analysis Days Selected: 7/17/03, 7/22/03 and 8/25/03 (shown in circles)
Low Analysis Day Selected: 8/15/03
Consecutive Event Days Selected: 7/16/03, 7/17/03 and 7/18/03

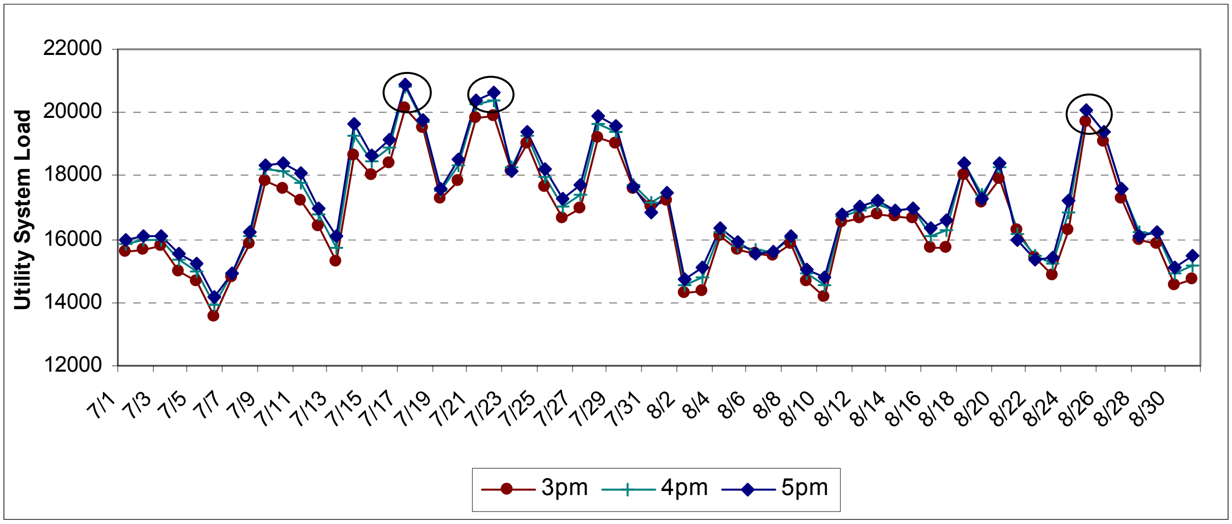


Exhibit 6-9
SCE System Load July and August 2003
High Analysis Dates Selected: 7/15/03, 8/14/03 and 8/18/03 (shown in circles)
Low Analysis Day Selected: 8/6/03
Consecutive Event Days Selected: 7/14/03, 7/15/03 and 7/16/03

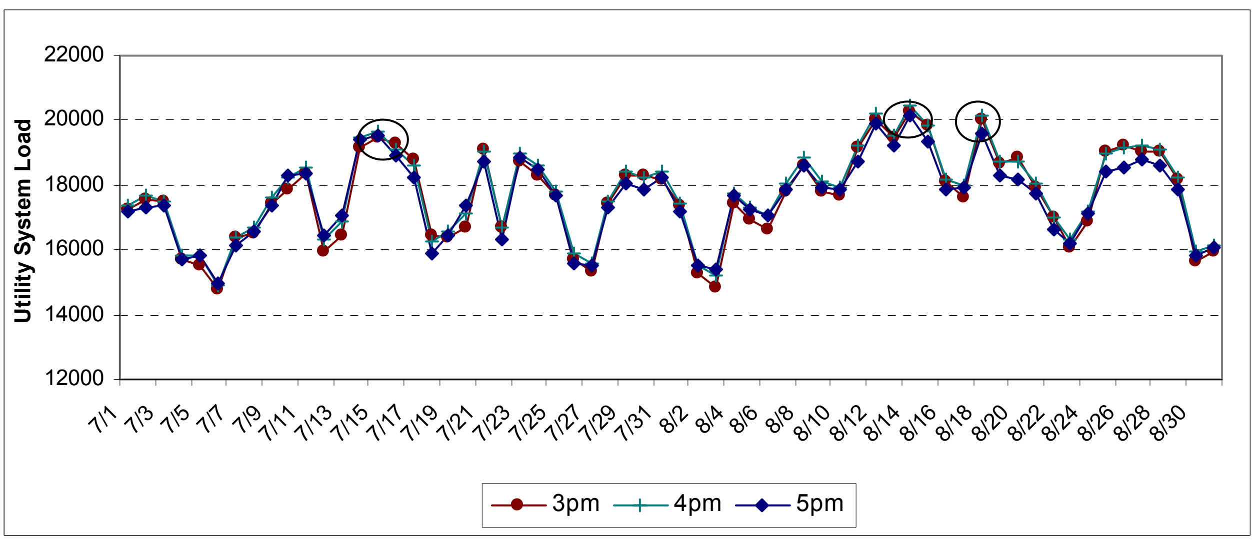
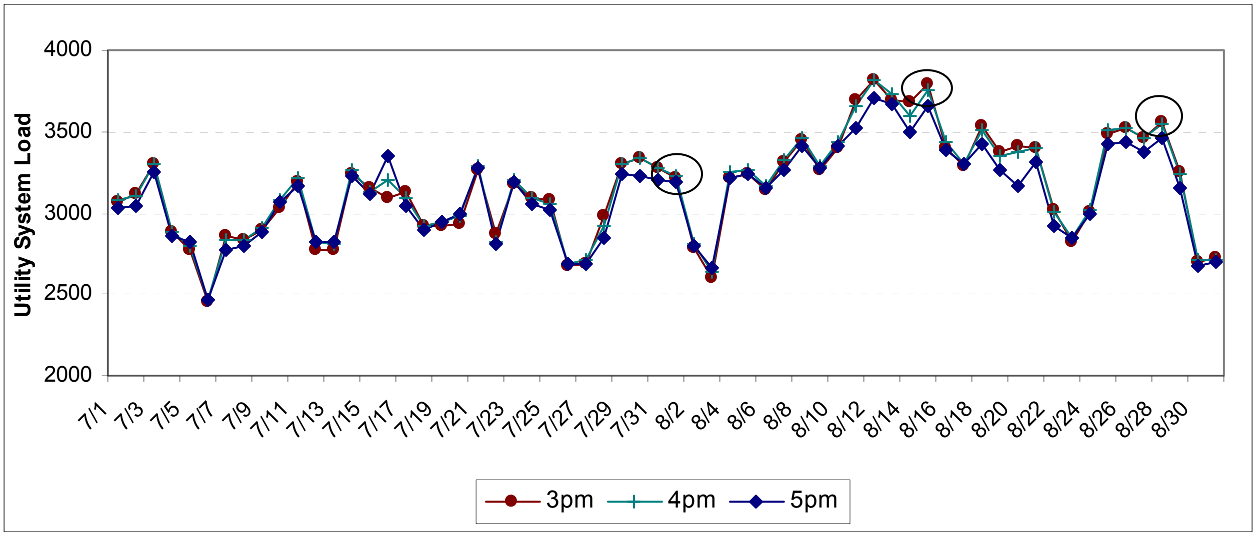


Exhibit 6-10
SDG&E System Load July and August 2003
High Analysis Dates Selected: 8/1/03, 8/15/03 and 8/28/03 (shown in circles)
Low Analysis Day Selected: 8/22/03
Consecutive Event Days Selected: 8/26/03, 8/27/03 and 8/28/03



Analysis Hours

The hours for which each of the CPP and DBP baselines were evaluated were dependant upon the range of curtailment hours for the DR program. Exhibit 6-11 provides the Analysis hours used for the CPP and DBP programs by utility.

Exhibit 6-11
Analysis Hours for the CPP and DBP Programs by Utility

	Evaluation Hours		
Program	**PG&E**	**SCE**	**SDG&E**
CPP	12 pm - 6 pm	12 pm - 6 pm	11 am - 6pm
DBP	12 pm - 8 pm	12 pm - 8 pm	12 pm - 8 pm

Analysis Population

The population used for the baseline analysis included all accounts selected for the non-participant quantitative survey conducted in March of 2004. This population was randomly selected using pre-defined strata (based on customer size and business type) in early March from the entire population of DR eligible non-participants. A small subset of the non-participant population was dropped because they did not have interval meters installed at their facilities and thus we could not obtain interval data for them. Exhibit 6-12 provides the breakdown of the non-participant quantitative survey population along with the baseline analysis population. The difference between these figures for PG&E and SDG&E represent the population lost due to the lack of interval meters.

Exhibit 6-12
Quantitative Survey Population versus Baseline Analysis Dataset

Utility	Quantitative Survey Population	Baseline Evaluation Population
PG&E	225	187
SCE	225	224
SDG&E	50	39
Total	500	450

Energy weights for all accounts in the quantitative survey population were created so that the sample analyzed would be representative of the entire DR eligible population. These energy weights were also used for the baseline analysis, however, a few of these weights required adjustment due to the lack of interval meter data for a subset of the non-participant population. The distributions of the baseline analysis population by size, business type, and size and business type are provided in Exhibits 6-13 through 6-15 below.

Exhibit 6-13
Distribution of Baseline Analysis Dataset by Utility and Size

Size	PG&E	SCE	SDG&E	Total
Small	34	51	6	91
Medium	41	68	13	122
Large	56	61	12	129
Extra Large	56	44	8	108
Total	187	224	39	450

Exhibit 6-14
Distribution of Baseline Analysis Dataset by Utility and Business Type

Business Type	PG&E	SCE	SDG&E	Total
Commerical	66	61	16	143
Industrial	86	105	11	202
Institutional	35	58	12	105
Total	187	224	39	450

Exhibit 6-15
Distribution of Baseline Analysis Dataset by Size and Business Type

Business Type	Small	Medium	Large	Extra Large	Total
Commerical	27	39	42	35	143
Industrial	39	61	57	45	202
Institutional	25	22	30	28	105
Total	91	122	129	108	450

The distribution of the baseline analysis dataset is representative of the entire DR eligible population. However, since in Chapter 4 it was shown that the participant population tends to be more heavily weighted to Large accounts and the Industrial sector, special attention will be paid to these segments throughout the course of the baseline analysis. Additionally, although the results presented in this section are based upon the analysis population (representative of the entire DR eligible population), the analysis was also run upon the participant population for the same analysis dates and the results were found to be similar.

6.2 BASELINE ANALYSIS METHODOLOGY

Three primary metrics were used to analyze the various baseline calculation methodologies. Two of the metrics utilized were taken from *Protocol Development for Demand Response Calculation – Findings and Recommendations*[3] (hereafter, "the CEC DR Protocol Report") a recent report focusing on analysis of demand response baseline methods prepared for the California Energy Commission. The goal of the CEC's analysis was to create a series of standardized measurement and verification protocols for use in calculating demand reductions of DR program participants and statistical metrics associated with measuring the bias, variability and overall error magnitude in the baselines. The third metric utilized regression techniques to measure the predictive power of the various baselines. The results from each of these metrics are provided in Section 6.3.

Metric 1: Baseline Bias

The *CEC DR Protocol Report* defined the bias in the baseline as "the systematic tendency to over- or under-state the baseline and corresponding demand reduction." To determine whether or not a particular baseline tends to be biased, we focus on the median relative hourly error for that baseline. This median error value represents the percent by which the calculated baseline tends to over-state (if greater than zero) or under-state (if less than zero) the baseline.

Calculating the relative hourly error for a particular baseline involves three steps. The first step is to calculate an hourly baseline for each account using one of the methodologies previously

[3] Prepared by KEMA-Xenergy in February of 2003 for the California Energy Commission. Copies of the report can be downloaded from the Commission's website at www.energy.ca.gov/demandresponse.

described (3-Day, 10-Day, 10-Day Adjusted, and Prior Day). Once the baseline has been calculated for each account, the next step is to calculate the hourly error associated with that baseline. The hourly error is the difference between the actual load for a particular hour and the estimated load for that hour based on the baseline. Finally, once these two values have been calculated, the relative hourly error can be calculated as the hourly error divided by the hourly load. Dividing the hourly error by the hourly load allows us to normalize the hourly error such that accounts of varying sizes can have equal significance. Once a relative hourly error has been calculated for all analysis accounts and curtailment hours, calculating the median relative hourly error across all of the accounts and hours allows us to determine whether or not any systematic biases exist for the baseline. If the median relative hourly error is positive then the baseline is more often than not over-stated, and thus the magnitude of the demand response is over-stated. If the median is negative then the baseline is more often than not under-stated, and thus the magnitude of the demand response is under-stated.

Metric 2: Baseline and Overall Error Magnitude

The *CEC DR Protocol Report* defined variability as "how wide the swings are around the typical or expected value", and Overall Error Magnitude as a measure that reflects both bias and variability in the baseline. To gauge an estimate of the variability and error magnitude of the baseline methodologies being evaluated, we follow the *CEC DR Protocol Report* approach of focusing on an account level statistic referred to as Theil's U, which is the account's relative root-mean-square hourly error. As shown below, Theil's U is calculated as the root-mean-square error divided by the root-mean-square load. Similar to the relative hourly error described above, this division by root-mean-square load serves to normalize the statistic for each account making the analysis independent of a customer's size. The root-mean-square error of an account is calculated as the square root of the sum of squares of the hourly errors divided by the number of hours in the curtailment period being evaluated.

$$Theil's\,U = \frac{\sqrt{\left[\sum_1^n E^2 / \sum n\right]}}{\sqrt{\left[\sum_1^n L^2 / \sum n\right]}}$$

$$\begin{aligned}
&where: \\
&E = HourlyError \\
&L = ActualLoad \\
&n = NumberofHoursCurtailmentPeriod
\end{aligned}$$

The root-mean-square error is similar to that of a simple standard deviation calculation in that it is the square root of the difference between the actual and the predicted values squared divided by the number of observations. Calculation of the root-mean-square load is done in a similar fashion with the exception that the hourly loads, as opposed to the hourly error, are being squared. This version of Theil's U statistic is similar to a coefficient of variation for load during peak hours. Because we are looking at deviations relative to the mean for each hour of the day, systematic differences across hours in the day do not affect this measure of variability, but differences in load from day to day do.

After Theil's U has been calculated for each account we focus our attention on the median and the 95^{th} percentile values across all accounts for each particular baseline methodology. The median Theil's U indicates the typical relative error magnitude for a typical account and the 95th percentile indicates the typical performance for accounts on the tail ends where the accounts performance is generally worse (extreme accounts).

Metric 3: Predictive Power of Baselines

The third baseline evaluation method utilized a regression equation model to predict energy use as a function of the baseline. The spirit of this method of analysis differs from that of methods one and two in which the forecast error was examined and instead focuses on determining how useful the baseline estimates are as predictors of energy use. In this regression the baseline was the only independent variable in a regression model of current energy use.[4]

To understand the differences between the approaches, one can view the forecast error approach as implicitly assuming the coefficient on the baseline value is one. In the predictor approach, the coefficient is allowed to vary in order to minimize the error between the actual value and the baseline value.[5] However, by aggregating across firms as well as over time, a restriction is imposed that this relationship between actual and baseline is consistent across time and firms. Another way to look at this relationship is that the coefficient is not constrained per se, but is the average error value across all the firms.

The basic regression equation used was the following which relates the current load for a customer ($Load_{it}$) as a function of various baseline estimates ($Base_{it}$):

$$Load_{it} = \beta Base_{it} + \varepsilon_{it}$$

where:

$Load_{it}$ = Current load for a customer i at time t

$Base_{it}$ = Baseline Estimate for customer i at time t

β = Parameter Estimate

ε_{it} = Error Term for customer i at time t

The predictive values of the potential baselines were examined using this model. In analyzing the results of this regression we focused on three main indicators. The first indicator examined

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[4] A constant term was not included, so the coefficient of determination (the R-squared) need not be bounded between zero and one. However, since all the estimated equations lack the constant term, comparison of the R-squared can be used to compare relative goodness of fit.

[5] Note that Theil's U is related to R-squared.

was the t-value associated with the regression model. The t-value gives the probability that we reject the null hypothesis (that is that $\beta = 0$). The larger the t-value, the smaller the confidence interval (thus the more precisely the coefficient has been estimated), and the higher the probability that we reject the null hypothesis. The second indicator focused on was the R-Squared value. The R-Squared value compares the goodness of fit between different baseline calculations. It measures the proportion of total variation about the mean explained by the regression. The closer the R-Square is to one the better the fit of the model. The third indicator of interest was the value of the parameter estimate β. The parameter estimate β represents the degree by which the baseline is over- or under-stated. If β is > 1 then the baseline can be said to be under-stated by (β - 1) percent. If β is < 1 then the baseline is over-stated by (1 - β) percent.

Modeling Issues

In the classical regression model, the error term (ε_{it}) is assumed to have uniform variance and be uncorrelated across observations.[6] Of course, problems can arise if these conditions are violated. One common problem is that the error terms do not have uniform variance. This is termed *heteroskedasticity* and arises in cases where the scale of the dependent variable (Load) and the explanatory power of the model tend to vary across observations. Essentially, greater variation in load is expected for firms that consume more energy than in smaller firms. In general, heteroskedasticity is cross-sectional (i.e., inter-firm) and for this analysis heteroskedasticity was handled by comparing (normalizing) the average error terms across facilities.

Another issue that can arise is where the variation in one period is correlated with the previous period, i.e., $\mathrm{Corr}[\varepsilon_{it}, \varepsilon_{it}\text{-}1] = \rho_i$. This can be explained if the factors omitted from the regression, like those included, are correlated across periods. This is termed *autocorrelation*. For this analysis a commonly accepted approach of correcting for autocorrelation was used that employed as a first step creating a simple AR(1) process (Auto Regressive model) to handle the correlation that exists between hours in an event day (i.e., if the baseline is over-stated for one hour of an event day, it is most likely over-stated for additional hours on that same event day). This AR(1) model follows a recursive process such that the error in one hour is a function of the error in the previous hour. Initially a model with a single auto-correlation coefficient (ρ) was used for all firms. Next, a second, more sophisticated, model was developed that looked at correlation over time specific to each firm (so that a ρ was estimated for each firm). Further regression analysis could be performed such that a ρ can be estimated individually for each firm for each day.

6.3 BASELINE ANALYSIS RESULTS

In this section a summary of the baseline analysis findings based on the metrics described in the previous section are presented for both the CPP and DBP programs.[7] The results are derived

[6] Essentially, the coefficients remain unbiased, but it no longer has the lowest variance and standard errors are incorrect.

[7] The main difference between the analysis results for the CPP and DBP programs is due to the differences in hours included in the analysis (12-8pm for DBP and 12-6pm for CPP for PG&E and SCE, and11-6pm for SDG&E).

from the non-participant sample selected for the March quantitative survey from all three utilities and weighted to represent the entire eligible DR population. The presentation of results is organized into sub-sections that address:

- Section 6.3.1 - All analysis day types (High Demand, Low Demand and Consecutive High Days) for the three baseline types (3-Day, 10-Day and Prior day) with and without adjustments,

- Section 6.3.2 - High versus Low versus Consecutive Demand days for the three baseline types (3-Day, 10-Day and Prior day) with and without adjustments,

- Section 6.3.3 - All analysis day types for small versus large accounts,

- Section 6.3.4 - All analysis day types for Commercial, Industrial and Institutional business types, and

- Section 6.3.5 - An examination of the effect of weather on the baselines.

A complete set of the analysis results for each of the individual utilities for DBP and CPP is provided in Appendix F.1.

It should be kept in mind that all of the results presented are based on analysis of load data for summer 2003 days between July 1, 2003 and August 31, 2003. Results might differ if weather conditions were to be substantially different than those in the study period.

6.3.1 All Baseline Analysis Days: 3-day, 10-Day, Prior Day Baselines

The initial component of the baseline analysis focused on all six of the analysis days (three high demand days, 1 low demand day and 2 high days consecutive to a high day) and the three main baseline types (3-Day, 10-Day and Prior Day) with and without adjustments for the weighted non-participant population. Exhibit 6-16 displays the load shapes for each of the distinct baselines, as well as the actual load, across the six analysis days. These load shapes were calculated as the average load for the non-participant population weighted to make it representative of the entire CPP and DBP eligible population and are averaged across all three utilities.

The calculations of the 10-Day and Prior Day baselines are identical for CPP and DBP. In some instances the CPP and DBP 3-Day baselines are somewhat different due to the fact that the hours used to determine the highest 3 days out of the last 10 similar days are slightly different and thus could lead to a different set of days being averaged.

Exhibit 6-16
3-Day, 10-Day (w/ and w/o Adjustments) and Prior Day Baselines versus Actual Load for All Analysis Days Averaged Over All Utilities

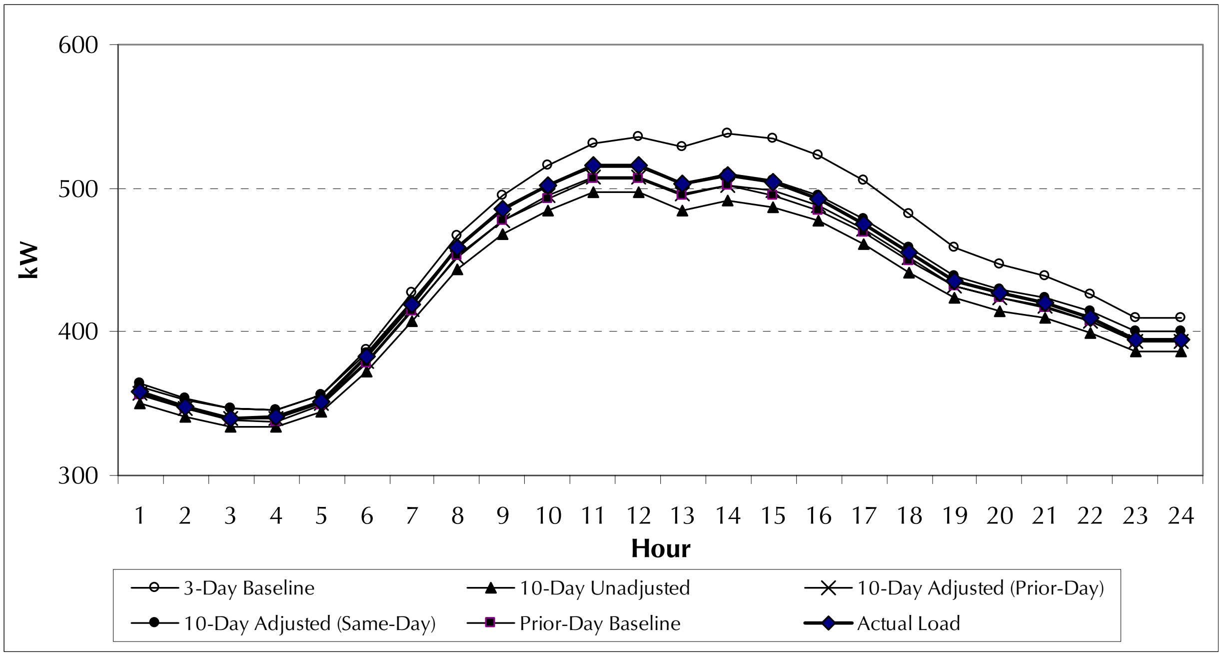


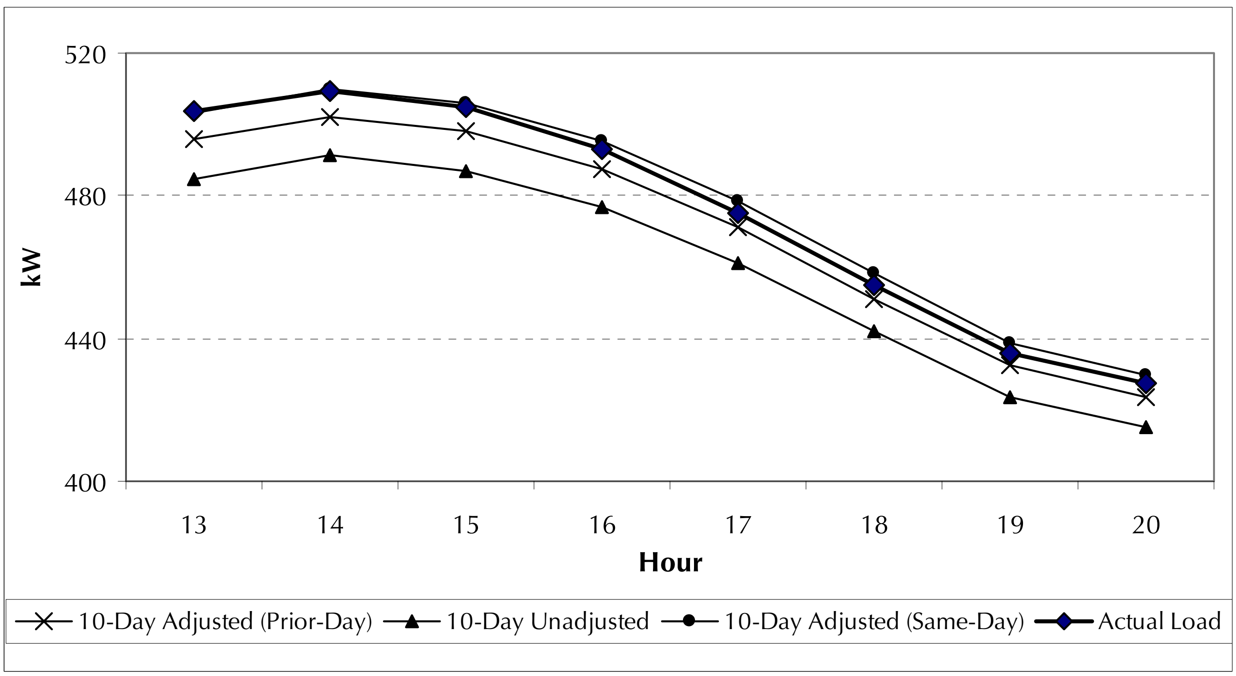
Exhibit 6-16 shows, as one might expect, that the 3-Day baseline tends to over-state the actual load since it is comprised of an average of three recent days with the highest load during the event period. A rationale behind the 3-Day baseline is that events are likely to be called on the hottest days of the summer. The degree to which the 3-Day baseline over-states the load is lessened when looking at solely high demand days, however, an overestimate still occurs. This tendency to over-state the load will also be seen when looking at the results of the bias diagnostics (the RHE or Relative Hourly Error) and coefficient of the regression modeling presented below. Exhibit 6-16 also shows that the 10-Day baselines tend to under-state the actual load. This too may be expected since the analysis days were selected to be similar to hypothetical event days, and thus tend to be higher load than an average day. Due to the scale and hours presented in this exhibit it is difficult to ascertain the precise impact of the adjustments on the 10-Day baseline, as a result, we present these in greater detail in the next exhibit and the discussion follows.

Finally, while the Prior Day baseline tends to be very close to the actual load on average, the diagnostics presented later in this chapter show that it has more variability, which is evident by looking at the t-values associated with the regression coefficients. This greater variability occurs because the Prior Day method is not an average over a series of days and thus changes in an organization's operation for one day have a much larger impact. As a result, the Prior Day baseline is a less reliable baseline on the whole.

Throughout the course of this section the results of the various baseline diagnostic metrics will be provided in detail to further support what is shown in the graphical averages presented in Exhibit 6-16 and, as discussed below, Exhibit 6-17. Exhibit 6-17 provides a magnified look at the

10-Day baselines for the DBP event hours, making it easier to see the effect of the prior-day and same-day adjustments on the 10-Day baseline. Both of these adjustments shift the 10-Day baseline up so that it becomes very close to the actual load. On average, the same-day adjustment has a slightly larger shift towards the actual load and is extremely accurate on average. This is due to its proximity to the actual prediction hours and, as shown in this exhibit for the analysis days selected, the same-day adjustment actually shifts it slightly higher than the actual load.

Exhibit 6-17
Close Up of 10-Day Baselines and Actual Load During DBP Event Hours for All Analysis Days Averaged Over All Utilities



BIAS – Metric 1

A key measure of bias in this evaluation is the median relative hourly error. Exhibit 6-18 below shows the median relative hourly error for the CPP and DBP baselines analyzed for this evaluation, which gives an indication of the bias associated with each specific baseline.

Exhibit 6-18
Bias Calculations for the CPP and DBP 3-Day, 10-Day and Prior Day Baselines with and without Adjustments for All Analysis Days across All Utilities

Baseline Details			Bias
Utility	**Baseline**	**Adjustment**	**Median RHE**
CPP	3-Day	None	0.020
	10-Day	None	-0.020
		Prior-Day	-0.003
	Prior Day	None	-0.003
DBP	3-Day	None	0.020
	10-Day	None	-0.020
		Prior-Day	-0.004
		Same-Day	0.002
	Prior Day	None	-0.003

Exhibit 6-18 illustrates that for both the CPP and DBP programs the 3-Day baseline consistently over-states the actual load. The average degree (based on the median) to which the 3-Day baselines are over-stated is 2 percent averaged across the entire sample for both the CPP and DBP programs. As mentioned earlier, these diagnostics, as well as the results of the error magnitude and regression analysis, are provided for each utility individually in Appendix F.1. Further analyses of the relative hourly errors broken down by analysis day type (high demand versus low demand), customer size (small versus large) and customer businesses type (Commercial, Industrial and Institutional) are also provided later in this section.

RELATIVE ERROR MAGNITUDE – Metric 2

Theil's U statistic calculated for a given account indicates the typical relative error magnitude for that account. The distribution of this statistic across accounts indicates the range of performance. We look at this distribution in terms of both the median and an extreme, the 95th percentile. The median Theil's U indicates the typical relative error magnitude for a typical account. The 95th percentile indicates performance in the worse cases.[8] Exhibit 6-19 below provides the median and 95th percentile Theil's U statistic for each of the distinct baseline types evaluated. These statistics provide an indication of the overall error magnitude associated with a specific baseline by measuring the size of the variability around the expected value, or in this case the actual load. The closer the statistic is to zero the smaller the relative error magnitude.

8 Protocol Development for Demand Response Calculation; prepared for the California Energy Commission, by Xenergy, Inc., Aug. 1, 2002 used this same approach. Most of the analyses in this section follow that protocol development.

Exhibit 6-19
Error Magnitude Calculations for the CPP and DBP 3-Day, 10-Day and Prior Day Baselines with and without Adjustments for All Analysis Days across All Utilities

Baseline Details			Error Magnitude	
Utility	**Baseline**	**Adjustment**	**Median Thiel's U**	**95% Thiel's U**
CPP	3-Day	None	0.099	0.749
	10-Day	None	0.091	0.473
		Prior-Day	0.081	0.495
	Prior Day	None	0.096	0.778
DBP	3-Day	None	0.090	0.517
	10-Day	None	0.093	0.486
		Prior-Day	0.085	0.516
		Same-Day	0.064	0.428
	Prior Day	None	0.085	0.528

As illustrated in Exhibit 6-19, for CPP, the typical error magnitude is minimized with the 10-Day adjusted (prior-day) baseline; however, the error magnitude for extreme accounts is minimized with the 10-Day unadjusted baseline (although they are very similar). Similarly for DBP, the 10-Day same-day adjusted baseline has an error magnitude that is almost 30 percent lower than that associated with the 3-Day baseline.

PREDICTIVE POWER – Metric 3

Exhibit 6-20 shows the results of the regression equation model used to predict energy use as a function of the baseline. The model coefficients in combination with the associated t-values and R-Square values give an indication of how useful the baseline estimates are as predictors of energy use.

Exhibit 6-20
Regression Coefficient with Associated t-value and R-Square for the CPP and DBP 3-Day, 10-Day and Prior Day Baselines with and without Adjustments for All Analysis Days across All Utilities

Day Type	Program	Baseline	Adjustment	Coef.	t-value	R-Square
Overall	CPP	3-Day	None	0.93	1,227	0.92
		10-Day	None	1.00	2,005	0.97
			Prior-Day	0.98	1,753	0.96
		Prior Day	None	0.96	1,345	0.94
	DBP	3-Day	None	0.93	1,107	0.91
		10-Day	None	0.99	1,739	0.96
			Prior-Day	0.95	1,575	0.95
			Same-Day	0.99	3,420	0.99
		Prior Day	None	0.90	869	0.86

Several important conclusions can be derived from the results presented in Exhibit 6-20. First, the 3-Day baseline significantly under performs as a predictor relative to most of the other choices. Second, the 10-Day baseline without any adjustment produces the best results for CPP, while the 10-Day same-day adjustment is the best predictor for DBP.[9] These results are consistent across utilities and day types. Third, the Prior day baseline is a very poor predictor relative to the other options, and it greatly over-estimates the actual load. Finally, except for a few cases, the baselines over predict the actual load, as nearly all the coefficients are less than one.

6.3.2 Impact of Day type (High Demand vs Low Demand vs consecutive Days) on 3-day, 10-Day, Prior Day Baselines

Because actual CPP and DBP events are more likely to be called on high demand days, a second analysis was performed on the same analysis days broken down by day type. This analysis helps to determine if the performance of the baselines varies based on whether an event day is a high demand day, a low demand day or a day that falls within a set of consecutively high demand days.

The baseline diagnostics that resulted from this analysis were very similar for all day types indicating there was not a drastic change in the baseline performance as a function of the type of event day, given summer 2003 weather conditions[10]. Exhibit 6-21 shows the average load shape for each of the baseline methods calculated as well as the actual load for a high demand day.

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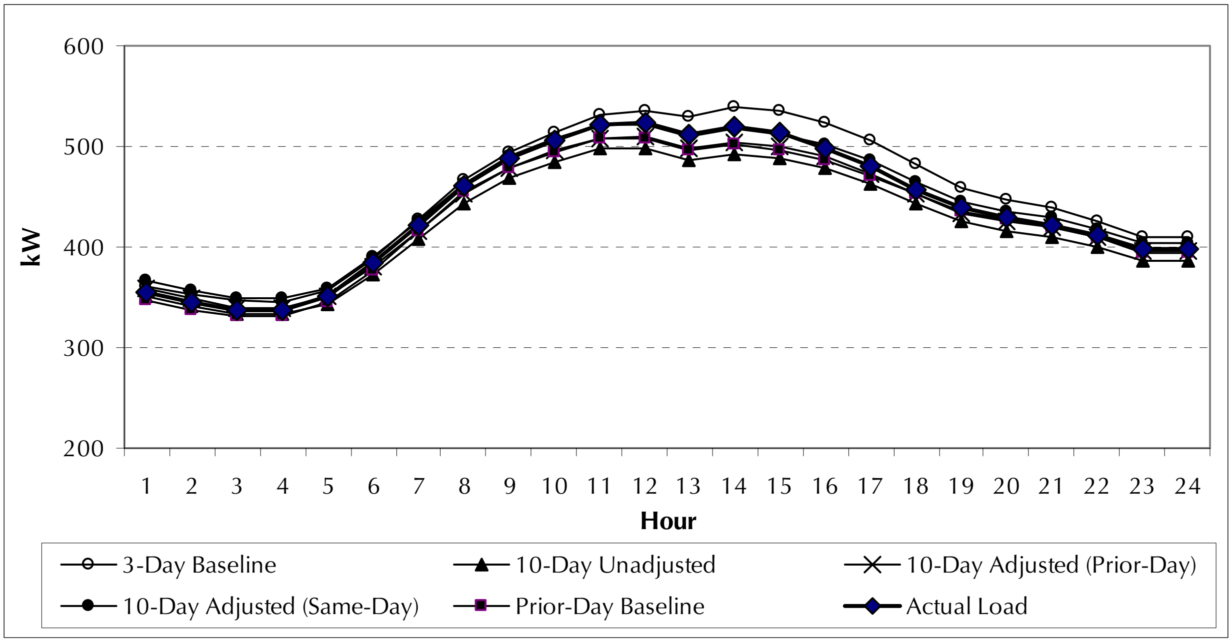
[9] We believe a same-day adjustment for the CPP period would also have outperformed the 10-Day unadjusted method for CPP had we included it.

[10] Readers should understand that the results in this chapter are based on the loads and underlying weather data for summer 2003. These results could differ under other weather conditions. The summer of 2003 is generally considered a relatively mild summer but this was not empirically investigated as part of this study.

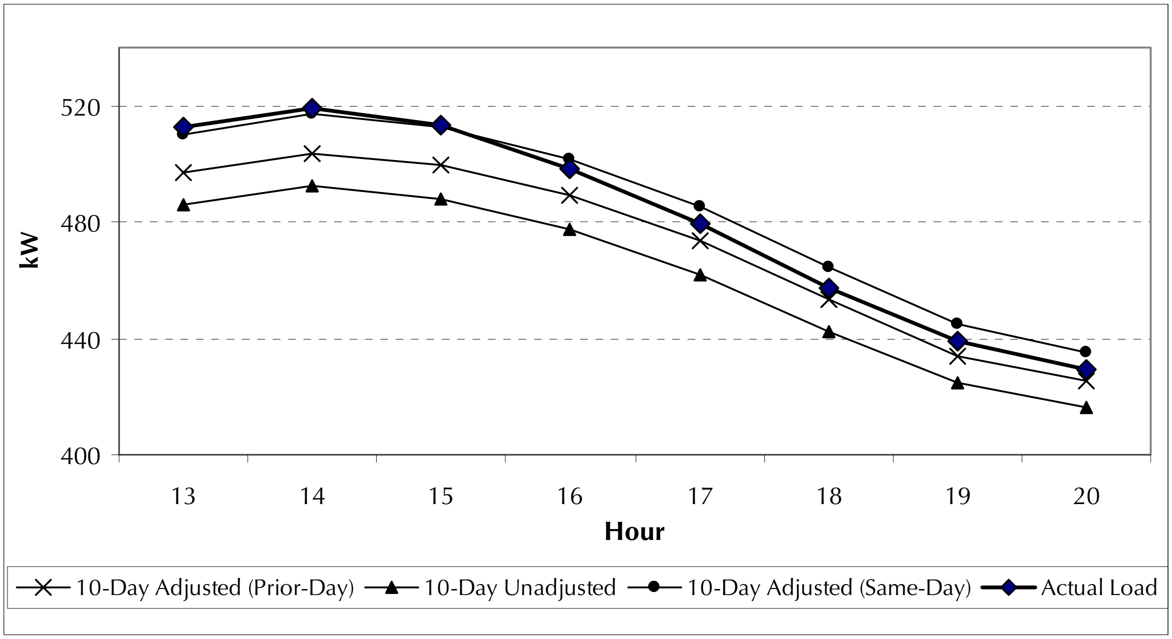
Exhibit 6-21
3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines versus Actual Load for High Demand Days Averaged Over All Utilities



As expected the difference between the 3-Day baseline and the actual load is smaller on high demand days and the amount by which the 10-Day baseline under-predicts the actual load is larger.

Exhibit 6-22 provides a magnified look at the all of the 10-Day baselines (adjusted and unadjusted) for the DBP event hours for the High Demand days.

Exhibit 6-22
Close Up of 10-Day Baselines and Actual Load During DBP Event Hours for High Demand Analysis Days Averaged Over All Utilities



BIAS – Metric 1

The bias calculations in Exhibit 6-23 illustrates that the 3-Day baseline tends to over-state the actual load to a higher degree on Low Demand days and Consecutive days and to a lesser degree on High Demand Days and the 10-Day baseline does the exact opposite. However, under all types of event days (High, Low and Consecutive) the 10-Day adjusted baselines continues to have the lowest amount of overall bias.

Exhibit 6-23
Bias Calculations for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines for High Demand Versus Low Demand Versus Consecutive Days Averaged Over All Utilities

Baseline Details			Bias - Median RHE		
Utility	**Baseline**	**Adjustment**	**High Dmd**	**Low Dmd**	**Consec**
CPP	3-Day	None	0.013	0.051	0.029
	10-Day	None	-0.027	0.010	-0.007
		Prior-Day	-0.008	0.002	-0.001
	Prior Day	None	-0.007	0.000	-0.001
DBP	3-Day	None	0.014	0.052	0.029
	10-Day	None	-0.026	0.009	-0.007
		Prior-Day	-0.008	0.001	-0.001
		Same-Day	0.002	-0.003	0.000
	Prior Day	None	-0.007	0.000	-0.001

RELATIVE ERROR MAGNITUDE – Metric 2

Exhibit 6-24 compares the error magnitude for High demand, Low demand and Consecutive days. As illustrated in this exhibit, the magnitude of the error is lower for the 10-Day baselines on Low demand days; however, the error at the extreme values tends to be higher on these days, which is to be expected.

Exhibit 6-24
Error Magnitude for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines for High Demand Versus Low Demand Days Averaged Over All Utilities

			Error Magnitude					
Baseline Details			Median Thiel's U			95% Thiel's U		
Utility	Baseline	Adjustment	High Dmd	Low Dmd	Consec	High Dmd	Low Dmd	Consec
CPP	3-Day	None	0.090	0.101	0.098	0.833	1.353	1.027
	10-Day	None	0.092	0.057	0.083	0.483	0.570	0.525
		Prior-Day	0.083	0.053	0.084	0.507	0.579	0.575
	Prior Day	None	0.102	0.069	0.100	0.739	0.835	0.753
DBP	3-Day	None	0.083	0.082	0.089	0.599	0.953	0.731
	10-Day	None	0.096	0.060	0.085	0.511	0.581	0.556
		Prior-Day	0.095	0.057	0.090	0.591	0.605	0.587
		Same-Day	0.064	0.055	0.053	0.443	0.501	0.500
	Prior Day	None	0.091	0.062	0.088	0.567	0.587	0.638

PREDICTIVE POWER – Metric 3

Exhibit 6-25 illustrates that in all instances the 3-Day baseline has a regression model coefficient β value that is less than one. This indicates that the 3-Day baseline is over-stated for both High and Low demand days. As mentioned earlier, the degree to which it is overstated can be calculated as "$1 - \beta$" percent. Hence for High demand days the 3-Day baseline for both CPP and DBP is overstated by 5 percent and for Low demand days it is overstated by 10 percent for DBP and 18 percent for CPP. The 10-Day baseline with no adjustments predicts extremely well for DBP, on average, on High demand days that is evident by coefficient estimate of 1.0 (while the CPP version shows a slight 2 percent under-statement). Similar to the 3-Day, the 10-Day baseline continues to over-state on Low Demand Days. The prior-day adjustment for CPP and the same-day adjustment for DBP improve upon both of the predictions for the Low demand days, and shifting the curves up slightly so that both of the baselines now over-predict the actual load by 1 percent on High Demand days.

Exhibit 6-25
Regression Coefficients with Associated t-values and R-Squares for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines for High Demand Versus Low Demand Days Averaged Over All Utilities

Day Type	Program	Baseline	Adjustment	Coef.	t-value	R-Square
High Demand	CPP	3-Day	None	0.95	1,343	0.94
		10-Day	None	1.02	1,912	0.98
			Prior-Day	0.99	1,625	0.96
		Prior Day	None	0.98	1,323	0.94
	DBP	3-Day	None	0.95	1,075	0.91
		10-Day	None	1.00	1,777	0.97
			Prior-Day	0.95	1,990	0.97
			Same-Day	0.99	3,564	0.99
		Prior Day	None	0.92	662	0.87
Low Demand	CPP	3-Day	None	0.82	983	0.94
		10-Day	None	0.88	1,245	0.98
			Prior-Day	0.90	1,138	0.96
		Prior Day	None	0.88	952	0.94
	DBP	3-Day	None	0.90	859	0.91
		10-Day	None	0.94	1,142	0.97
			Prior-Day	0.93	1,102	0.97
			Same-Day	1.00	2,131	0.99
		Prior Day	None	0.88	662	0.87
Consecutive	CPP	3-Day	None	0.93	1,266	0.94
		10-Day	None	1.00	1,997	0.98
			Prior-Day	0.98	1,522	0.96
		Prior Day	None	0.96	1,247	0.94
	DBP	3-Day	None	0.94	1,023	0.91
		10-Day	None	1.00	1,611	0.97
			Prior-Day	0.95	1,475	0.97
			Same-Day	0.99	2,659	0.99
		Prior Day	None	0.91	809	0.87

6.3.3 Impact of Customer Size (Small, Medium, Large or Extra Large) on 3-day, 10-Day, Prior Day Baselines

As shown in Chapter 4, although Large and Extra Large customers (those with demand greater than 1MW) only make up 12 percent of the population eligible for CPP and DBP, currently they comprise 28 percent of all program participants and account for 77 percent of the total energy enrolled in the program. For this reason, a separate analysis was completed to evaluate the performance of the baselines by customer size.

Exhibits 6-26 and 6-27 show the average load shapes for the 3-Day, the 10-Day and the 10-Day adjusted baselines as well as the actual loads for the largest CPP and DBP eligible customers (those maximum demand > 1 MW) and the smallest CPP and DBP eligible customers (those maximum demand < 1 MW).

Exhibit 6-26
3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines versus Actual Load for the Largest Eligible Customers (Maximum Demand > 1 MW) Averaged Over All Utilities

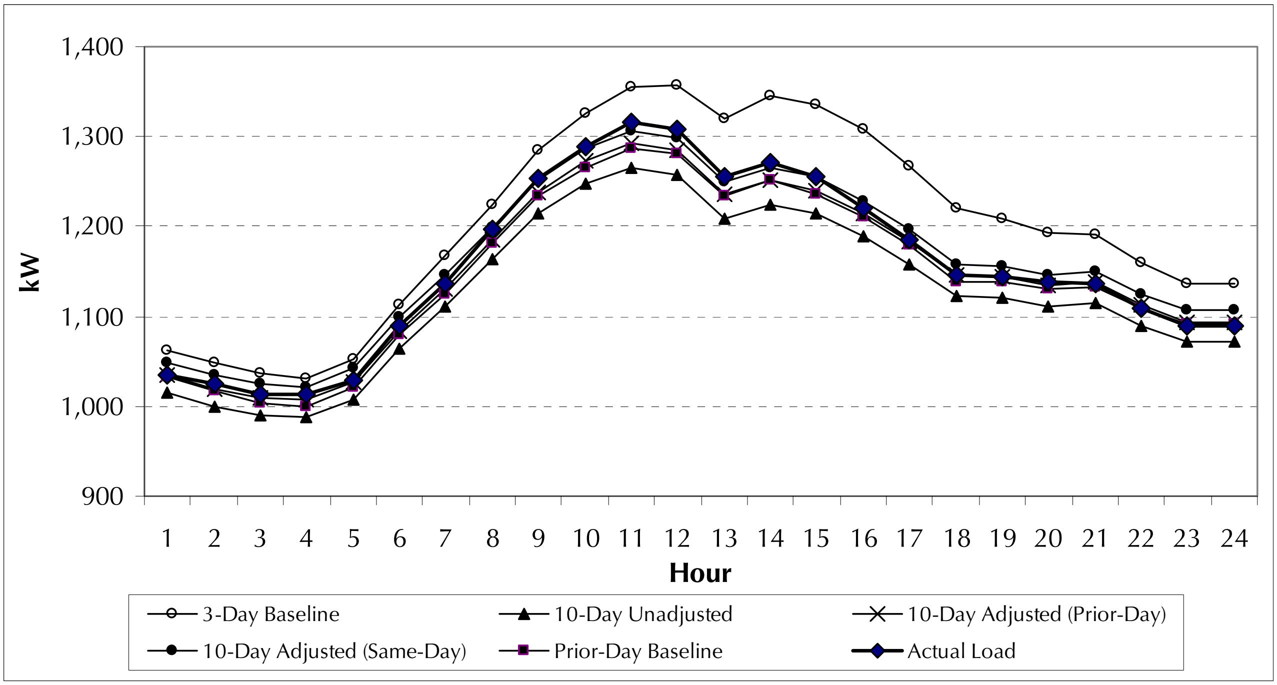
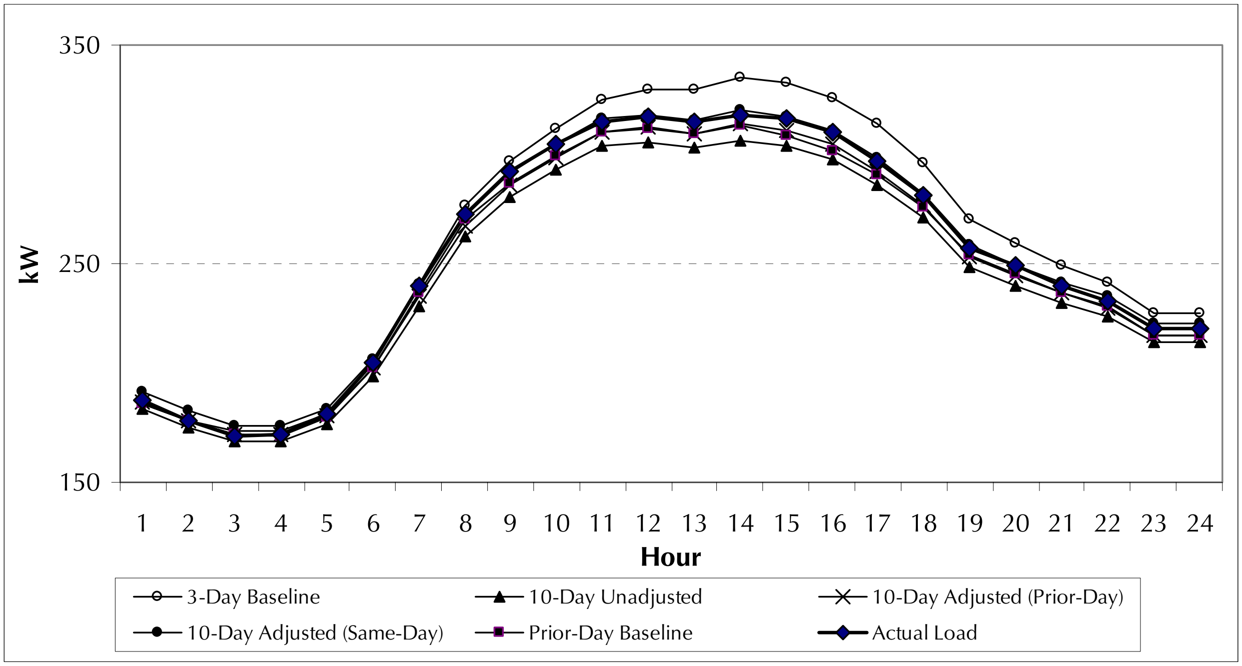


Exhibit 6-27
3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines versus Actual Load for the Smallest Eligible Customers (Maximum Demand < 1 MW) Averaged Over All Utilities



BIAS – Metric 1

Exhibit 6-28 compares the bias in the baselines for the entire analysis population by customer size (Small – 100–500 kW for SDG&E and 200-500kW for SCE and PG&E, Medium – 500-1,000 kW, Large – 1,000-2,000 kW, and Extra Large greater than 2,000 kW). This exhibit illustrates that there is no clear correlation between the level of bias in the baseline and the customer size. This exhibit also shows that the 10-Day adjusted consistently is the best predictor of bias regardless of size.

Exhibit 6-28
Bias Calculations for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines by Customer Size Averaged Over All Utilities

Baseline Details			Bias - Median RHE			
Program	**Baseline Type**	**Adjustment**	**Small**	**Medium**	**Large**	**Extra Large**
CPP	3-Day	None	0.026	0.013	0.025	0.017
	10-Day	None	-0.024	-0.030	-0.017	-0.012
		Prior-Day	-0.002	-0.005	0.000	-0.004
	Prior Day	None	-0.001	-0.006	-0.001	-0.004
DBP	3-Day	None	0.027	0.014	0.026	0.018
	10-Day	None	-0.024	-0.030	-0.016	-0.013
		Prior-Day	-0.004	-0.005	0.000	-0.004
		Same-Day	0.001	0.000	0.005	0.001
	Prior Day	None	-0.001	-0.006	-0.001	-0.004

RELATIVE ERROR MAGNITUDE – Metric 2

Exhibit 6-29 compares the error magnitude for the entire analysis population by customer size.

This exhibit shows again that there is no clear correlation between the error magnitude associated with the baseline and customer size. Again the 10-Day adjusted continues to minimize the error magnitude across all size categories.

Exhibit 6-29
Error Magnitude for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines by Customer Size Averaged Over All Utilities

Baseline Details			Error Magnitude - Median Theil's U			
Program	**Baseline Type**	**Adjustment**	**Small**	**Medium**	**Large**	**Extra Large**
CPP	3-Day	None	0.118	0.089	0.114	0.081
	10-Day	None	0.111	0.083	0.112	0.068
		Prior-Day	0.108	0.073	0.106	0.071
	Prior Day	None	0.122	0.076	0.121	0.082
DBP	3-Day	None	0.102	0.081	0.108	0.072
	10-Day	None	0.108	0.082	0.119	0.070
		Prior-Day	0.112	0.071	0.118	0.079
		Same-Day	0.084	0.052	0.088	0.048
	Prior Day	None	0.111	0.068	0.110	0.072

PREDICTIVE POWER – Metric 3

Exhibit 6-30 illustrates that most of the methods perform similarly for all sizes except the smallest customers. A significant decrease in predictive accuracy as measured by the model co-efficient can be seen particularly for the 3-Day unadjusted and the Prior Day baseline methods. This indicates that smaller sized customers have more variation on a day-to-day basis than larger customers and thus the 3-Day baseline shows that for CPP, it overstates the actual load by 12 percent and for DBP by 14 percent. The Prior Day baseline shows even worse performance for the small DBP customers with the baseline overstating the actual load by almost 50 percent.

Exhibit 6-30
Regression Coefficients with Associated t-values and R-Squares for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines by Customer Size Averaged Over All Utilities

Customer Size	Program	Baseline Type	Adjustment	Coef	t-value	R-Square
Extra Large	CPP	3-Day	None	0.95	754	0.93
		10-Day	None	1.00	1,503	0.97
			Prior-Day	0.99	1,451	0.96
		Prior Day	None	0.97	1,034	0.92
	DBP	3-Day	None	0.93	695	0.91
		10-Day	None	0.99	1,275	0.95
			Prior-Day	0.97	941	0.96
			Same-Day	0.99	3,277	0.99
		Prior Day	None	0.93	714	0.86
Large	CPP	3-Day	None	0.94	798	0.93
		10-Day	None	1.00	1,121	0.97
			Prior-Day	0.96	941	0.96
		Prior Day	None	0.94	686	0.92
	DBP	3-Day	None	0.94	859	0.91
		10-Day	None	1.00	961	0.95
			Prior-Day	0.95	814	0.93
			Same-Day	0.99	1,508	0.99
		Prior Day	None	0.85	515	0.86
Medium	CPP	3-Day	None	0.94	830	0.93
		10-Day	None	0.99	944	0.97
			Prior-Day	0.96	795	0.96
		Prior Day	None	0.93	539	0.92
	DBP	3-Day	None	0.92	656	0.91
		10-Day	None	0.99	755	0.95
			Prior-Day	0.92	627	0.93
			Same-Day	0.98	1,178	0.99
		Prior Day	None	0.75	344	0.86
Small	CPP	3-Day	None	0.88	695	0.93
		10-Day	None	0.95	679	0.97
			Prior-Day	0.94	729	0.96
		Prior Day	None	0.91	538	0.92
	DBP	3-Day	None	0.86	361	0.91
		10-Day	None	0.95	417	0.95
			Prior-Day	0.86	339	0.93
			Same-Day	0.97	713	0.99
		Prior Day	None	0.54	161	0.86

Measuring Impacts of Small Customers

Analyzing the relationship between the error in the baseline and a customer size is an interesting area of analysis in particular in light of discussions and proposals that have occurred to consider reducing the minimum size of customers allowed to participate in the CPP and DBP programs. One question that has come up with regards to the CPP and DBP programs is if program eligibility is expanded to include smaller customers (smaller than 100 kW) will the impacts be able to be distinguished from the noise around the baseline? Better understanding the distribution of any systematic errors in the baselines can inform estimation of what size load reduction would need to be required of customers of different sizes to be attributable to the program. For example, if customers with a peak demand below 200 kW are allowed to participate in these programs, the minimum load reduction must be small enough to be achievable, but not so small that it is lost in the error associated with the baseline calculation. Since the baseline dataset does not contain any customers whose peak demand is below 200 kW (other than a small sample between 100-200 kW for SDG&E), we cannot directly address what the expected error would be for individuals smaller than 200 kW. However, the analysis population can give a glimpse into the expected error for small customers.

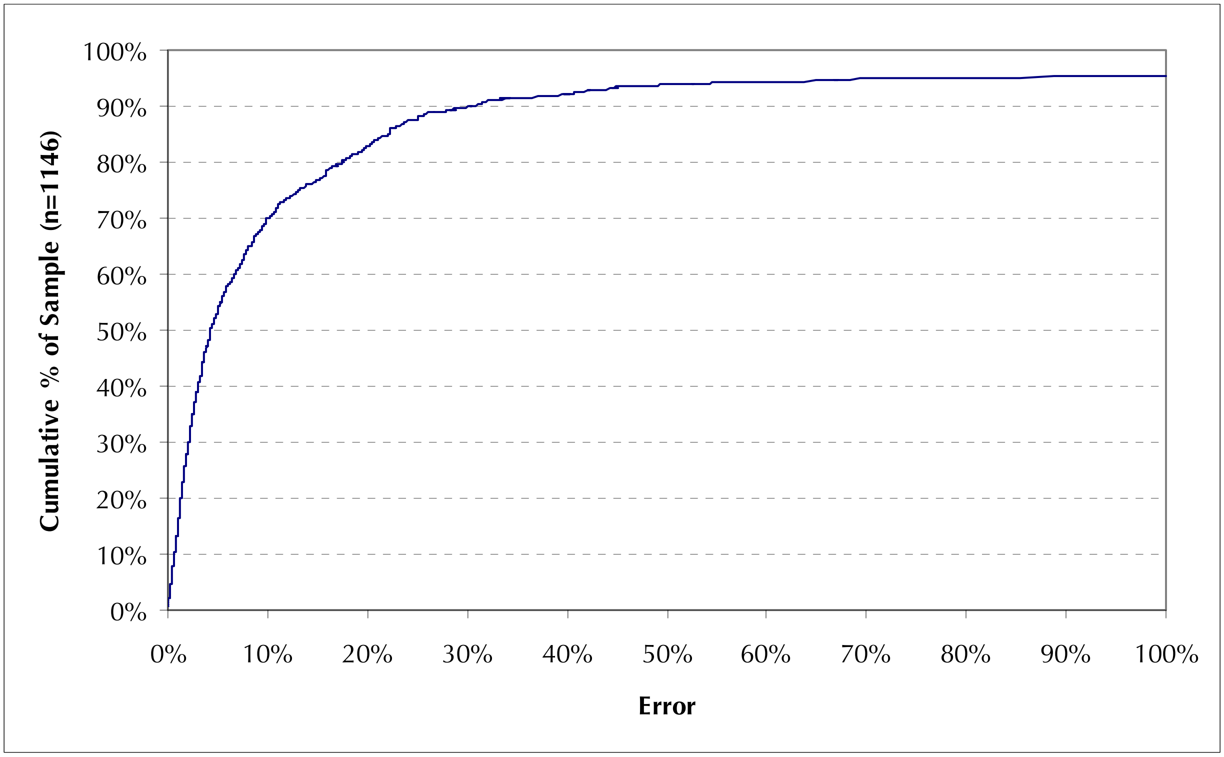
To address this question, the baseline error calculation was altered slightly to capture the absolute percentage error between the baseline and the actual load for the smallest group of customers. That is, the absolute relative error was calculated as:

Absolute Relative Error = |(Actual Load – Baseline)|/(Actual Load)

The absolute relative error was used to avoid the issue of overestimation versus underestimation. The baseline used in this analysis was the DBP 3-Day baseline, as the 3-Day approach is currently being used for these programs, and the issue of errors for small customers is particularly important for DBP since it determines whether or not a customer is paid for their participation or lack of participation.

This absolute error term was computed for the smallest group of customers, i.e., customers with a peak demand between 100 and 200 kW. There were only 25 such customers in the sample since currently only SDG&E allows customers of this size to participate in the program and thus they are part of the eligible non-participant population. As expected from the preceding analysis, the median value of the absolute error for the 100 to 200 kW population is small, at only 4 percent. This means the difference between the baseline and the actual load can be expected to be less than 8 kW for at least 50 percent of small participants. Exhibit 6-31 shows the cumulative distribution for the errors for this sample of very small customers (for each hour during a potential DBP event).

Exhibit 6-31
Cumulative Distribution of Error for DBP 3-Day Baseline
for Very Small Sized Customers (100-200kW)



One of the interesting conclusions from this graph is that the distribution of the errors has an extremely long tail, with errors exceeding 100 percent. However, this graph also shows that there are a number of observations that have very low errors, with 75 percent of the sample having an error of 13 percent or less. Therefore, it should be possible to measure with a relatively high degree of confidence a load reduction to 13 kW for a 100 kW customer.

The question then becomes how does this distribution compare to the distribution for customers who are smaller than 100 kW? Since the current eligible population, and thus the analysis sample, does not have any information on these very small customers, it was not possible to investigate this population directly. Instead, a different approach was used to see if there was a correlation between the relative absolute error and the size of the customer. A similar analysis of the relative absolute errors was conducted for customers with demand between 200 and 500 kW (567 such customers), customers with demand between 500 and 1,000 kW (451 customers), customers demand between 1,000 and 2,000 kW (315 customers), and customers greater than 2,000 kW (256 customers). A comparison of the relative absolute errors was made across customer size segments to determine if there was any correlation between the size of the relative absolute error and customer size. The cumulative distributions of the errors for these populations are included in Appendix F.2.

In general, the cumulative distribution graphs show that the error distribution is similar across size categories, though the customers with demand between 200 and 500 kW have the tightest distribution, while the largest customers have the broadest distribution. Exhibit 6-32 summarizes the distributions across the 5 size categories for all of the utilities.

Exhibit 6-32
Distribution of Error at Selected Percentiles of Sample across Size Categories

Customer Size Group	Error (%) at Selected Percentiles of Sample		
	50%	75%	90%
Very Small (100 to 200 kW)	4%	13%	31%
Small (200 to 500 kW)	4%	10%	25%
Medium (500 to 1,000 kW)	6%	15%	39%
Large (1,000 to 2,000 kW)	6%	15%	50%
Extra Large (2,000+ kW)	5%	16%	50%

It appears that the resulting cumulative distribution of absolute relative error is relatively similar across all customer size categories and therefore there is no evidence to suggest that smaller customers under 100 kW have significantly larger absolute relative errors than the 100-200 kW or 200-500 kW customers. The exhibit above indicates that it is likely that half of the observations from smaller customers (less than 100 kW) will have an error on the order of 5 percent or less.

An additional conclusion from the previous exhibit is that the 100 kW minimum reduction limit for DBP may be too strict for smaller customers, as the expected error in the baseline estimate is significantly below this amount for customers with demand less than 500 kW. These results tend to support the conclusion that a tiered structure may be more appropriate, that has lower minimum reduction limits for smaller customers. Currently if a 5 MW customer bids 100 kW (the minimum allowable bid) for a DBP event, a 2 percent reduction for this account, it may be hard to detect and possibly impossible to measure since the exhibit above shows that median percent error for the sample for a customer of this size is 5 percent. Whereas a 25 kW reduction for a 100 kW customer (a 25 percent reduction) may be much easier to measure.

6.3.4 Impact of Business Type (Commercial, Industrial, Institutional) on 3-day, 10-Day, Prior Day Baselines

Because different types of customers may have different load shapes and different factors driving load shape changes over time, we investigated the performance of the baseline methods as a function of customer type. Given the available sample to work with, business types were organized into three groups – Industrial, Institutional, and Commercial. In Chapter 4 it was shown that Industrial customers make up 29 percent of the eligible population for CPP and DBP, currently comprise 37 percent of all program participants, and account for 62 percent of the total energy signed up. Conversely, Institutional customers make up 28 percent of the eligible population for CPP and DBP, comprise 23 percent of all program participants, and account for only 16 percent of the total energy signed up for one or both of the programs.

Exhibits 6-33 and 6-34 illustrate the differences between the actual load and the 3-Day and 10-Day baselines for each of the business types. No significant differences in performance by business type are readily apparent in the summary graph.

Exhibit 6-33
DBP 3-Day Baselines versus Actual Load
for Industrial, Commercial and Institutional Customers across All Utilities

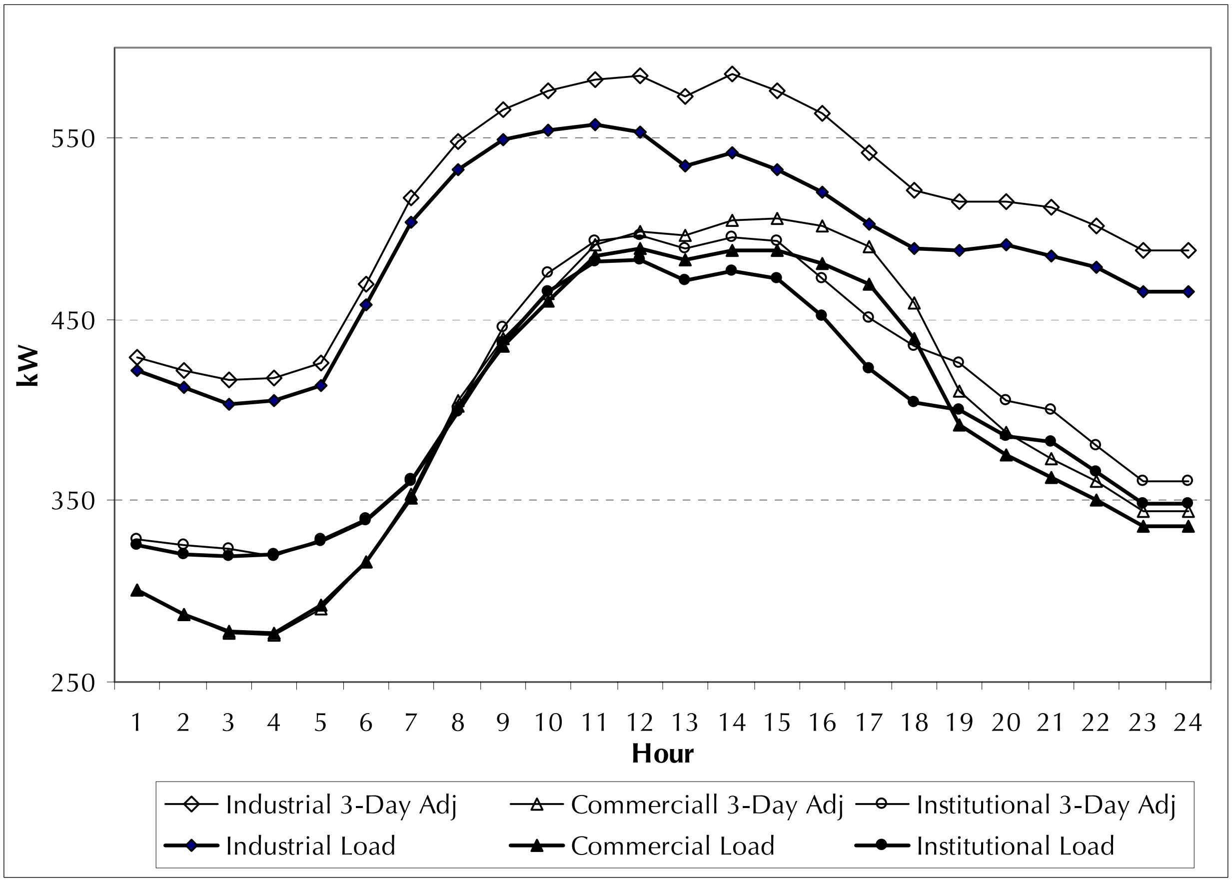
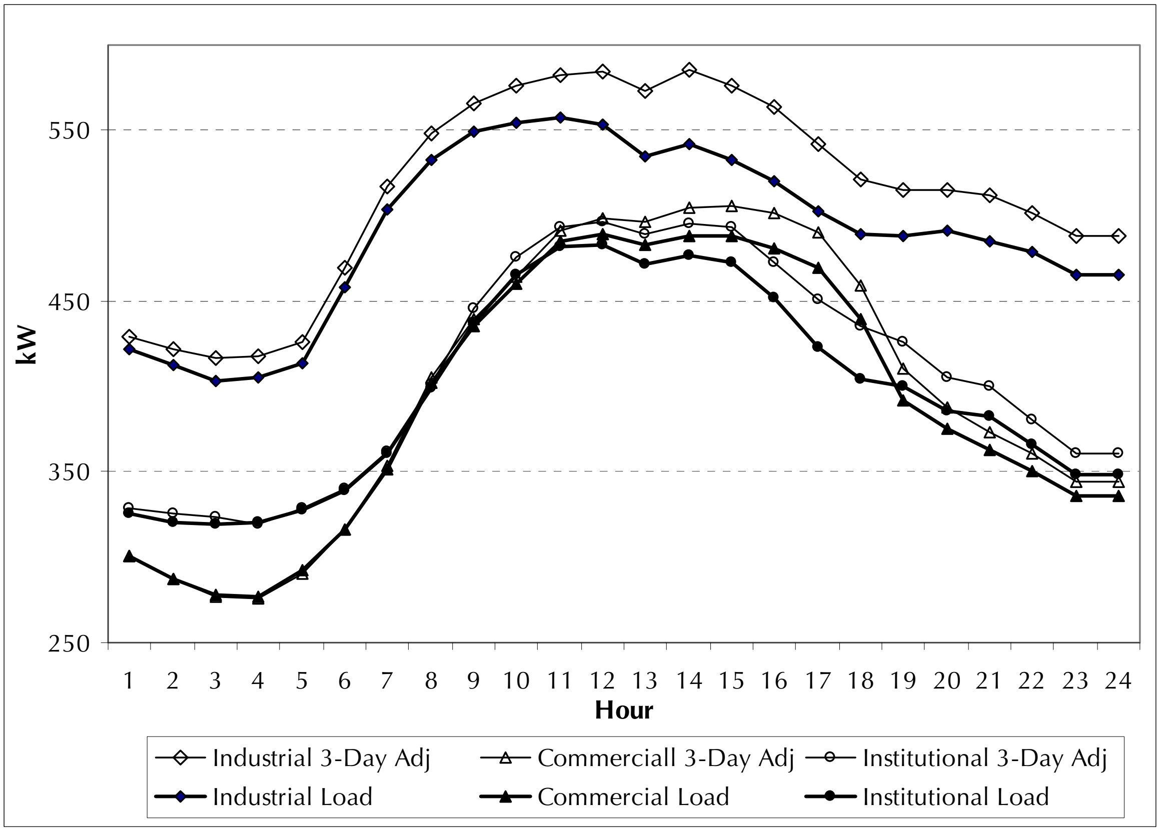


Exhibit 6-34
DBP 10-Day Baselines versus Actual Load
for Industrial, Commercial and Institutional Customers Across All Utilities



BIAS – Metric 1

Exhibit 6-35 presents the bias diagnostic results for the Industrial, Commercial and Institutional sectors. The 3-Day baseline for Industrial customers has approximately twice the bias as it does for the smaller Commercial or Institutional customers for both the CPP and DBP programs. This increased tendency for the 3-Day baseline to over-state the actual load is most likely a function of the increased variability in the magnitude of load from day-to-day for the Industrial sector. Accounts in the Commercial sector tend to have a more consistent load on similar days and thus the bias associated with a baseline that selects the highest three days out of 10 is more likely to be representative of any given similar day. Exhibit 6-34 also shows that the 10-Day non-adjusted baseline understates the actual load for all business types, however, the understatement seems to be slightly minimized for Industrial customers. The Prior day and same-day adjustments again provide significant improvements over both the 3-Day and the 10-Day non-adjusted for all customer business types.

Exhibit 6-35
Bias Calculations for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines by Business Type Averaged Over All Utilities

Baseline Details			Bias - Median RHE		
Program	**Baseline Type**	**Adjustment**	**Industrial**	**Commerical**	**Institutional**
CPP	3-Day	None	0.029	0.014	0.015
	10-Day	None	-0.014	-0.024	-0.021
		Prior-Day	-0.002	-0.005	-0.001
	Prior Day	None	-0.002	-0.007	0.000
DBP	3-Day	None	0.030	0.014	0.017
	10-Day	None	-0.015	-0.024	-0.019
		Prior-Day	-0.002	-0.006	-0.001
		Same-Day	0.002	0.001	0.003
	Prior Day	None	-0.002	-0.007	0.000

An interesting item to note from Exhibit 6-35 is that for both the CPP and DBP programs the Prior day baseline has zero bias for Institutional customers. This indicates that variation from one day to the next for Institutional customers in the sample on average is very small.

RELATIVE ERROR MAGNITUDE – Metric 2

Exhibit 6-36 below shows that despite this small average day-to-day variation the overall error magnitude for extreme accounts is between 2 and 6 times larger for Institutional customers.

Exhibit 6-36
Error Magnitude of the Prior Day Baselines for Extreme Accounts by Business Type Averaged Over All Utilities

	Error Magnitude - 95th Percentile Theil's U		
Program	**Industrial**	**Commerical**	**Institutional**
CPP	0.763	0.563	3.637
DBP	0.556	0.466	1.157

Exhibit 6-37 below compares the error magnitude for Industrial, Commercial and Institutional customers. As one might expect, the median Theil's U for Industrial customers for the 3-Day baseline is nearly double that of customers in the Commercial sector. This too corroborates the explanation of why the 3-Day baseline performs worse for Industrial customers.

Exhibit 6-37
Error Magnitude for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines by Business Type Averaged Over All Utilities

Baseline Details			Error Magnitude - Median Theil's U		
Program	**Baseline Type**	**Adjustment**	**Industrial**	**Commerical**	**Institutional**
CPP	3-Day	None	0.125	0.070	0.134
	10-Day	None	0.107	0.073	0.130
		Prior-Day	0.100	0.071	0.104
	Prior Day	None	0.121	0.077	0.133
DBP	3-Day	None	0.111	0.066	0.119
	10-Day	None	0.114	0.077	0.119
		Prior-Day	0.104	0.070	0.112
		Same-Day	0.093	0.052	0.106
	Prior Day	None	0.101	0.069	0.125

PREDICTIVE POWER – Metric 3

The regression results by business type are shown in Exhibit 6-38.

Exhibit 6-38
Regression Coefficients with Associated t-values and R-Squares
for the 3-Day, 10-Day (w/ and w/o Adjustment) and Prior Day Baselines
by Business Type Averaged Over All Utilities

Business Type	Program	Baseline Type	Adjustment	Coef.	t-value	R-Square
Commercial	CPP	3-Day	None	0.97	893	0.93
		10-Day	None	1.01	932	0.94
			Prior-Day	0.98	961	0.95
		Prior Day	None	0.97	684	0.92
	DBP	3-Day	None	0.96	676	0.93
		10-Day	None	0.99	895	0.95
			Prior-Day	0.94	557	0.94
			Same-Day	0.97	707	0.96
		Prior Day	None	0.82	316	0.87
Industrial	CPP	3-Day	None	0.89	888	0.93
		10-Day	None	0.96	935	0.94
			Prior-Day	0.93	986	0.95
		Prior Day	None	0.92	815	0.92
	DBP	3-Day	None	0.95	806	0.93
		10-Day	None	1.00	948	0.95
			Prior-Day	0.95	884	0.94
			Same-Day	0.97	950	0.96
		Prior Day	None	0.89	542	0.87
Institutional	CPP	3-Day	None	0.93	977	0.93
		10-Day	None	0.99	1,059	0.94
			Prior-Day	0.97	1,136	0.95
		Prior Day	None	0.95	957	0.92
	DBP	3-Day	None	0.96	1,090	0.93
		10-Day	None	1.00	1,219	0.95
			Prior-Day	0.96	1,143	0.94
			Same-Day	0.99	1,636	0.96
		Prior Day	None	0.94	816	0.87

6.3.5 Weather Effects

In an effort to investigate the effect of weather in the relationship between actual load and the baseline, the regression model used in the above analysis was expanded to include weather terms. That is, the model was changed to:

$$Load_{it} = \beta Base_{it} + \varphi W_{it} + \varepsilon_{it}$$

where:

$Load_{it}$ = Current load for a customer i at time t

$Base_{it}$ = Baseline Estimate for customer i at time t

W_{it} = Weather conditions (temperature and humidity) for customer i at time t

β,φ = Parameter Estimates

ε_{it} = Error Term for customer i at time t

The dataset used for the baseline analysis had weather data for 320 customers. These observations were used to develop two estimates of the ability of the 10-Day with the prior day adjustment and the 10-Day unadjusted baselines to predict actual load. The results are shown in Exhibit 6-39.

Exhibit 6-39
Predicting Actual Load with Baselines and Weather

Program	Baseline Type	Adjustment	Without weather terms			With weather terms		
			Coef.	T-Value	R-squared	Coef.	T-Value	R-squared
CPP	10-Day	None	1.02	299.94	0.80	1.00	286.57	0.83
DBP	10-Day	Same-Day	0.99	468.85	0.90	0.99	417.93	0.91

These results indicate that adding weather terms and other independent variables has very little effect on the relationship between the baseline and the actual loads. In general, adding weather terms has the effect of slightly increasing the R-Squared of the model, and decreasing the t-value of the baseline variable. For CPP, adding weather terms changes the coefficient on the baseline term slightly, bringing it close to 1. While these results suggest that there is little added benefit to accounting for weather conditions when comparing the baseline to the actual load, the added variables were statistically significant. Therefore, omitting these variables may result in somewhat biased results (due to omitted variable bias). However, past research has shown that the decrease in bias with the addition of these variables does not outweigh the complexity that is added to the baseline calculation. Due to the timing with which the weather was data was delivered for the 2004 evaluation it was not possible to complete a further analysis of weather effects on baseline performance for this report. However, this should be considered for further analysis in subsequent CPP/DBP evaluations.

6.4 SUMMARY OF CONCLUSIONS

The results of our analyses of alternative hourly load baselines lead to the following conclusions, given the 2003 load and weather data used:

- The 10-Day Baseline with Same Day Adjustment is the most accurate of the methods evaluated and should be used as the basis for the same-day DBP program impact estimates in this evaluation study (see Chapter 7). We are not necessarily recommending that this baseline be used for DBP settlement purposes. This decision needs to factor other issues, such as assessing the cost and benefits involved in making such a change.

- For previous day programs and events, the 10-Day unadjusted and 10-Day with prior-day adjustment are relatively similar in performance and both are superior to their 3-Day counterparts. We recommend using the 10-Day with prior-day adjustment method for calculating overall program impacts for day-ahead DBP and CPP.

- The 3-Day Baseline with no adjustment, which is currently used for settlement in the DBP program, performs less well than 10-Day methods and appears to produce a consistently large over-estimate of the baseline. The extent to which the 3-Day Baseline with no adjustment over-estimates impacts in the 2004 program is discussed in Chapter 7.

- The Prior Day Baseline is the poorest performing baseline in terms variability and predictive accuracy, but has low bias. This method is not recommend for use in settlement or impact evaluation.

7. CPP AND DBP IMPACT EVALUATION

This section summarizes the impact assessment portion of the 2004 WG2 Demand Response program evaluation.

7.1 OBJECTIVES AND SCOPE OF IMPACT EVALUATION

The purpose of the impact evaluation is to provide evaluation-based estimates of the load reductions associated with the CPP and DBP programs for summer 2004. Note that this 2004 program evaluation was conducted on a relatively real-time[1] basis beginning in January 2004 and continuing through the summer and fall. Historically, most DSM evaluations have been conducted six months to a year after the close of a previous program year. From a process and market evaluation point-of-view, real-time evaluation offers the obvious benefit of obtaining feedback from program participants when program experiences are fresh and allows program managers and policy makers to consider this information in deciding whether to make same-year program adjustments. A relatively real-time evaluation approach was designed by WG2 for these programs to drive the evaluation toward results that would be timely enough to aid decision-making associated with the CPUC's program filing processes for 2004 program adjustments and 2005 program offerings. At the same time, real-time evaluation can pose significant challenges, particularly when it comes to impact evaluation. In the case of this evaluation, these challenges include the following:

- Time lags associated with data availability. The hourly interval data required for this evaluation must go through the utilities revenue metering Validating Editing and Estimation" (VEE) process. This process typically takes 2 to 6 weeks. Since the evaluation must be finalized by mid-December, the WG2 evaluation team decided that only data made available to the evaluation team by October 15th, 2004 would be analyzed. Several program events that occurred in late September and October are not captured. The lag time associated with getting the VEE data after October 15th made it impractical to include these events in the analyses and still meet the project deadlines.

- In some cases, the number of participants in a utility's program changed rapidly throughout the program evaluation period, for example, in PG&E's CPP.[2] Ideally, we would like to analyze impacts across all of the CPP events; however, because the participant pool was changing throughout the events, care must be taken in this process.

- Many types of data are required for the impact evaluation, including hourly load data, event notification data, weather data, price data, and bidding data. Obtaining all of

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[1] By "real-time" we mean evaluation activities that occur concurrently with program activities during the same program year, or that follow the end of the program year within several months.

[2] As of May 1st, 2004 (the first day of the summer season and the first day to potentially call a CPP event) PG&E had only 21 accounts signed up for CPP. On October 31, 2004 (the last day of the summer season and the last day to call a CPP event) PG&E had increased their enrollment in CPP by 117 accounts to a total of 138 accounts. Further participation details can be found in Section 4.

these data from three different utilities on a close to real-time basis is difficult, particularly, the first year that evaluation-based data transfer protocols are established.

- Another challenge in conducting the impact evaluation is the number of participants in the program, their level of activity,[3] and the fact that the programs are being modified by the utilities. As a result, when considering what analyses to conduct, it is important to consider the value of the information that would be produced by different types of analyses. The approach taken in this project is to use methods that estimate and illustrate the 2004 impacts. These impacts are augmented by data analyses of closely associated findings (e.g., impacts by participating segments). No attempt was made to develop formal models that could be used to forecast impacts of these programs under different conditions. The limited base of information available from this startup year of these programs along with the modifications to programs that have already been discussed by the utilities make the development of forecasting models difficult and of limited usefulness. However, some qualitative insights are generated, but formal modeling is not believed to be appropriate given the nascent status of the programs and time constraints of this initial evaluation.

Despite these challenges, the evaluation team has successfully compiled enough information to develop useful first-year estimates of the CPP and DBP programs within the context and constraints of the 2004 program and market environment.

As noted above, this impact assessment does not include a quantitative forecast of overall program potential.[4] However, a qualitative discussion of several 2004 program caveats that lead us to believe that the 2004 program impacts most likely represent a lower bound on what these programs may be able to deliver in the future.

7.2 IMPACT EVALUATION METHODOLOGY

7.2.1 Overview

The objective of the impact evaluation is to determine the first-year program demand impacts. The impact evaluation encompassed all participants that were enrolled in the programs on the individual event days with interval meter data that could be provided by the utilities to the

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[3] For example, the DBP program was only triggered two or fewer times (per utility) and, with the exception of SDG&E, exclusively on a same-day test event basis.

[4] This 2004 impact evaluation does not include a quantitative forecast of potential program impacts under conditions different from 2004 (which included limited DBP experience [e.g., 2 same-day only DBP tests], low levels of CPP participation at SCE, low market prices, and a generally low level of customer-perceived reliability need). To include such an assessment in future analyses would require the advanced specification of methods to be employed such that the analysis would lead to defensible quantitative point forecasts outside the range of conditions observed for the 2004 program year.

evaluation team. The method employed is referred to as the Representative Day Approach.[5] This approach is implemented for two of the baseline methods described and analyzed in Chapter 6: the 3-Day and 10-Day Adjusted Baseline methods.

7.2.2 Data Sources for Impact Evaluation

The impact evaluation for the WG2 Summer 2004 programs uses data from four primary data sources for each utility: billing interval meter data, CPP and DBP event data, weather data,[6] and participation data. Additionally, telephone survey data was used to supplement the data from the three utilities. A summary of the data elements available for use in the impact evaluation is presented below.

Billing Interval Meter Data

Each of the three utilities sent Quantum Consulting (QC) a series of datasets containing interval meter data for all CPP and DBP participants as well as a sample of non-participants. QC merged these datasets together, by utility, to create a unique interval meter database for each utility. These databases include 15-minute increment billing interval meter data from January 2003 through September 2004 along with various account and meter identifiers used to link to the other data sources. For each of the utilities there were a few participants missing from the interval meter data. Since all participants are required to have interval meters installed in order to be eligible to participate, it is assumed that this missing data is a result of either an error in the files used by the utilities to identify participants or due to some transmission difficulties.

CPP and DBP Event Data

For each CPP and DBP event, an event dataset was created and delivered to QC. These datasets contained event information such as results of the notification process, the event type (day-of or day-ahead), the event hours, the event triggers (temperature, price, system emergency, etc.), and the estimated payment amount for DBP events.

Weather Data

The hourly temperature and humidity data for each of the utility's load research weather sites was collected and appended to the interval meter databases using a weather station identifier. This weather data was used in the impact evaluation to identify weather sensitive accounts and

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[5] A number of alternative estimation approaches were also considered, including the development of multivariate statistical models. Given the number of events, the changes in participation over the summer, and the changes that are anticipated for these programs, it was judged that the representative day approach was a robust estimation approach and the additional information that might be gathered from the multi-variate modeling was unlikely to provide additional useful information that would warrant the cost and time of this more detailed examination of the data. However, these approaches may be appropriate for application to a data set that had larger numbers of participants and events. As a result, these alternative methods may be tested and applied in the 2005 evaluation.

[6] Price data were originally specified and relevant for the day-ahead DBP events because load reductions would be paid at a value of between 15 and 50 cents per kWh reduced, depending on market prices. However, no day-ahead DBP events occurred in 2004. Price data associated with the CPP tariff may also be used and are readily available from the tariff itself.

to evaluate potential impacts in light of the day's climate conditions. For PG&E there were 25 unique weather sites, for SCE there were 24 unique weather sites, and for SDG&E there were 10 unique weather sites.

Participation Data

Each of the three utilities sent QC a series of datasets containing the most recent population of customers participating in the CPP and DBP programs. These datasets contained the names and customer identifiers for each participant, the date the customer became effective in the program, flags indicating whether the customers had enrolled in either the Technical Assistance Incentive or Bill Protection (for CPP only) programs. For PG&E this file also contained the committed load reduction estimates that are used in place of bids for same-day DBP events.

Telephone Survey Data

A subset of the available telephone survey data collected during the Post-Event and End-of-Summer surveys was used in the impact evaluation. The two telephone surveys resulted in completed surveys for a total of 161 unique customers. The data collected in the telephone surveys supplied information on a customer's bidding and curtailment activity for recent events as well as their estimates of the resulting load impacts. This information was merged together with the interval data for each of the event days to provide further distinction for accounts where curtailment activity was not necessarily evident from the interval data. Merging this information together also allowed us to examine the relationship between the actions a customer thought or said they took compared to the response evident in the interval meter data. For each of the customers interviewed, data was collected for a maximum of 6 of the events.

For a detailed discussion of the telephone survey and the final sample disposition, see Section 5. The final frequency tables for the Post-Event and Final Evaluation telephone surveys can be found in Appendix E.

7.2.3 Evaluation Population

All utility customers that were signed up for either the CPP or the DBP program at the time an event was called and had interval meter data provided to the evaluation team will be included in the impact assessment population. For PG&E, the population of participants as of the most recent event was 130 accounts for CPP and 78 accounts for DBP. For SCE, the participant populations included 8 accounts for CPP and 558 accounts for DBP. The population of participants for SDG&E as of the end of the summer was 52 accounts for CPP and 47 accounts for DBP, however as of the last CPP and DBP event only 48 and 37 participants were signed up for CPP and DBP respectively. Due to technical difficulties with the notification software notification could only be confirmed with 8 of SGD&E's 47 participants for the third CPP event. However, since an event announcement was posted to their website and the load reductions across the participants did not reflect a lack of notification all participants were included in the results. A complete discussion of the participant and 2004 events is discussed in Chapter 4.

7.2.4 Evaluation Analysis Period

Impacts were calculated for all CPP and DBP events for which there existed a nearly complete set of interval data as of October 15, 2004 (this date was determined based on the final reporting requirements of the WG2 proceeding). Due to the timing of the utilities' monthly data processing and the WG2 reporting time restrictions, we were unable to calculate impacts for the final PG&E CPP event (CPP Event #5) that took place on October 13th. The first SCE DBP test event that took place on November 19th, 2003 was also excluded from the analysis since it fell outside the summer 2004 timeframe and had only a fraction of the current signups at that time. Exhibit 7-1 and 7-2 presents the summer 2004 CPP and DBP events by utility.

Exhibit 7-1
Initial 2004 CPP Events by Utility

Utility	Event	Event Type	Event Trigger	Event Date	Event Hours	Participants
SDG&E	CPP - #1	day-ahead notice	Utility Discretion	07/13/04	11-6 pm	41
	CPP - #2	day-ahead notice	Utility Discretion	07/22/04	11-6 pm	42
	CPP - #3	day-ahead notice	Utility Discretion	08/11/04	11-6 pm	47
	CPP - #4	day-ahead notice	Utility Discretion	09/01/04	11-6 pm	47
	CPP - #5	day-ahead notice	Utility Discretion	09/08/04	11-6 pm	47
	CPP - #6	day-ahead notice	Utility Discretion	09/23/04	11-6 pm	48
SCE	CPP #1	day-ahead notice	Temperature	07/14/04	12-6 pm	8
	CPP #2	day-ahead notice	System Constraint	07/22/04	12-6 pm	7
	CPP #3	2-day notice	Temperature	08/11/04	12-6 pm	8
	CPP #4	2-day notice	Temperature	08/12/04	12-6 pm	8
	CPP #5	2-day notice	Temperature	09/03/04	12-6 pm	8
	CPP #6	2-day notice	Temperature	09/09/04	12-6 pm	8
	CPP #7	2-day notice	Temperature	09/10/04	12-6 pm	8
	CPP #8	2-day notice	Temperature	09/13/04	12-6 pm	8
	CPP #9	2-day notice	Temperature	09/14/04	12-6 pm	8
	CPP #10	2-day notice	Temperature	09/23/04	12-6 pm	8
	CPP #11	2-day notice	Temperature	09/24/04	12-6 pm	8
	CPP #12	2-day notice	Temperature	09/27/04	12-6 pm	8
PG&E	CPP #1	day-ahead notice	Temperature	08/27/04	12-6 pm	112
	CPP #2	day-ahead notice	Temperature	09/08/04	12-6 pm	119
	CPP #3	day-ahead notice	Temperature	09/09/04	12-6 pm	119
	CPP #4	day-ahead notice	Temperature	09/10/04	12-6 pm	119
	CPP #5	day-ahead notice	Temperature	10/13/04	12-6 pm	129

Exhibit 7-2
Initial 2004 DBP Events by Utility

Utility	Event	Event Type	Event Trigger	Event Date	Event Hours	Participants
SDG&E	DBP #1	day-of notice	System Constraint	05/03/04	3-5 pm	25
	DBP #2	day-of notice	Test	06/30/04	3-7 pm	37
	DBP #3	day-of notice	System Emergency	09/07/04	3-5 pm	47
SCE	DBP #1	day-of notice	Test	06/09/04	3-7 pm	473
	DBP #2	day-of notice	Test	09/23/04	3-7 pm	558
PG&E	DBP #1	day-of notice	Test	07/26/04	4-6 pm	78

7.2.5 Representative Day Approach Impact Methodology

The primary impact analysis methodology employed is referred to as the *Representative Day Approach*. Given the nascent status of the CPP and DBP programs, the low levels of active bidding in the DBP test events, priority interest in assessing the differences among baseline methods, and the time constraints associated with the completion of this final report by mid-December 2004, the evaluation team concluded that it was most important to focus initially on utilizing the representative day approach for the 2004 impact evaluation. As program participation grows, it is likely that alternative multivariate statistical impact evaluation methods will be necessary and employed. The WG2 Evaluation Committee is considering implementing and comparing methods that might include other multi-variate statistical approaches to the representative day approach using data from summer 2004 in next year's evaluation study.

Another commonly used evaluation approach, referred to as the *Control Group Approach* involves metering a control group of non-participating customers and then using their load as a proxy for the participants' behavior. This approach, as with all approaches, has its strengths and weaknesses. For the 2004 impact evaluation this approach was considered, however for a number of reasons[7] is not recommended at this time.

The *Representative Day Approach* constructs a "typical day" or baseline using load and/or weather data from the days preceding the event day. This impact evaluation approach involves computing an hourly baseline for all program participants for each of the event days and then calculating the difference between the baseline and the actual load for the event day. The

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[7] The control group approach was not recommended by the evaluation team for the CPP/DBP evaluation for several reasons. First, unlike the WG3 programs, no control groups were designed into the evaluation (since the WG2 programs were not pilots and thus were open to all eligible customers). Second, the non-participant sample that was developed for this evaluation was designed to be representative of the eligible population not the current participant population. Additionally, because the participant population is changing rapidly over time, it would not have been possible to select a control group early in the project that would assuredly be representative of the final group of participants. Finally, many large nonresidential customers have unique load shape patterns and, even under ideal circumstances, it may not be possible to find a group of non-participants that can be reliably considered an analytical proxy for the behavior of the participants.

overall participant difference (or delta) for a given event is then simply the sum of the differences across the program participants:

$$Difference_t = \sum_n \left(k\hat{W}_{n,t} - kW_{n,t} \right)$$

where,

$Difference_t$ = Difference between the estimated baseline load and the actual load at time t,

$k\hat{W}_{n,t}$ = Estimated baseline load of customer n for event t, and

$kW_{n,t}$ = Actual load of customer n for event t.

Based on our analysis of the various customer baseline methodologies presented in Section 6 of this report, two sets of baselines were selected for use in calculating the summer 2004 program impacts. The first set of baselines used to calculate the event impacts were the CPP and DBP 3-Day baselines. These baselines were selected since they are the baselines currently used for settlement in the existing CPP and DBP programs at each of the three utilities. The second set of baselines used for the impact calculations are the CPP and DBP 10-Day Adjusted baselines (using both a prior-day and same-day adjustment). These baselines were selected since they most accurately represented the customer load shapes based on our baseline analysis in Section 6.

7.2.6 Counting Estimated Load Differences

One determinant that can affect the final program impact calculation under the Representative Day approach is which of the load differences should be attributed to the program. Based on the baseline analysis summarized in Section 6, it was evident that there is a moderate amount of uncertainty, both positive and negative, surrounding the baseline estimates. Errors in the baseline estimates will, of course, lead to errors in the corresponding impact estimates. A baseline with a positive bias, (relative hourly error) on average over-states the load for a "typical day" and thus is likely to overestimate the resulting load impacts. In other words, the difference between the estimated load and actual load may be positive even when the customer takes no action. Conversely, a baseline with a negative bias tends to underestimate the load in the absence of an event and thus will often underestimate the load impact.

Small random errors from the baseline methods should generally cancel each other. Of more concern are potentially biased baseline estimates that are systematically high or low. However, there are several aspects of the program and our analysis that make isolation of program effects tractable:

- many of the load shape changes are quite large and obvious for those program participants that do take action,
- DBP program bids are required which provide a strong indication of whether customers load shape changes are intentional,

- for a sample of program participants, we have obtained customer reports of whether they intentionally took action, and

- an analysis of baseline methods was conducted on a range of day-types for summer 2003 for which the actual load shape was known; this allows us to develop estimates of whether alternative methods are systematically biased and, if so, to what extent.

There are a variety of alternative strategies to deal with the small random errors that can be employed to differentiate the true program impacts from the noise surrounding the baseline. The three alternatives examined to determine what load reductions to count in the program impact estimates include counting all differences (both positive and negative regardless of size), counting only the positive differences, and counting all differences that are greater than a pre-determined tolerance level. These alternatives are described below.

Alternative 1: Include All Differences

The first alternative that can be used to calculate the total program impact over all customers is to include all differences that exist between the baseline and the event day for all customers. This strategy has the advantage that, if the baseline is unbiased, then small positive and negative differences (that are not necessarily attributable to the program) tend to cancel each other out. However, if the baseline is shown to be slightly biased (either over- or under-stated) then the majority of the small errors will be either positive or negative and thus the overall program impact may also be over- or understated. This alternative was used to count load reductions for the CPP impact analysis.

Alternative 2: Include All Positive Differences

A "positive" difference in this discussion refers to a reduction in the customer's load during an event hour as compared to the calculated baseline (i.e., savings are defined as positive). Under this alternative all event hours in which a customer impact is greater than zero are summed to determine the overall event impact. This approach can be viewed as calculating the upper bound for the actual event impact since it includes what may be either small random positive changes or small systematically biased positive changes between the baseline and the actual load. In theory, if the baseline method is unbiased, it also introduces a systematic bias in that small negative changes are not also counted. For a bidding program such as DBP this alternative may be appropriate for counting all differences for those accounts that bid, however, it may not be the best approach for the remaining accounts. This approach has been used by PG&E for reporting initial impacts for both the CPP and DBP programs. This alternative was used to count load reductions for the DBP impact analysis in this study. However, had the evaluation team had more time for the analysis, we may have chosen one of the other alternative methods. This is an area that should be examined further in the 2005 evaluation.

Alternative 3: Include All Differences Greater than a Minimum Difference Tolerance

A third alternative that can be used when calculating the impact of an event is to include all differences that are greater than a pre-determined "tolerance". This "tolerance" is the minimum difference that must exist in order for the difference to be attributable to the program. There are a number of ways the tolerance can be set. If a baseline tends to be over-stated, setting the tolerance at 10 or 20 kW will minimize the amount of this over-statement that is passed into the final event impact. If the reverse is true and the baseline tends to be understated, setting the tolerance at –20 kW and then including the absolute value of all impacts greater than –20 kW will make a similar adjustment and reduce the under-statement of the final impact. Another approach that can be used sets a unique tolerance for each participant based on a percent of their annual maximum load. When using such an approach it is best to also set a cap, or a maximum tolerance level, such that large customers do not have tolerances that exclude impacts most likely to be attributable to the program. So for instance, if the threshold were set at a 10 percent level with a cap of 100 kW (the minimal paid reduction for the DBP program), an account with an annual maximum load of 250 kW would have a tolerance of 25 kW, an account with an annual maximum load of 900 kW would have a tolerance of 90 kW and an account with an annual maximum load of 3,000 kW would have a tolerance of 100 kW.

Although we originally intended to analyze and thoroughly compare this approach to the two other alternatives above, the time available between receipt of the final interval data in late October and filing of this evaluation on December 16, 2004, did not allow for completion of this effort. Again, this is an area that should be examined further in the 2005 evaluation.

Illustration of the Different Alternatives

Exhibit 7-3 shows an example of the effect of the different methods of counting estimated load differences for 10 hypothetical accounts. For individual accounts, the choice of treatment can result in a large impact (e.g., Accounts 5 and 10). In this example the total differences for the 10 hypothetical accounts examined in aggregate are small (e.g., a difference of 2 percent). Differences in these accounting approaches for the actual 2004 participants will be developed and compared in the results section.

Exhibit 7-3
Hypothetical Effects of Load Difference Accounting Alternatives

Account	Baseline (kW)	10% Tolerance (kW)	Actual Load (kW)	Load Reduction (kW)	Percent Reduction	Alternative 1: All Differences	Alternative 2: All Positive Differences	Alternative 3: Differences > 10% Tolerance
Account 1	600	60	550	50	8%	50	50	0
Account 2	350	35	400	-50	-14%	-50	0	0
Account 3	400	40	300	100	25%	100	100	100
Account 4	3,000	100	2,700	300	10%	300	300	300
Account 5	200	20	5	195	98%	195	195	195
Account 6	1,200	100	800	400	33%	400	400	400
Account 7	225	23	255	-30	-13%	-30	0	0
Account 8	240	24	165	75	31%	75	75	75
Account 9	600	60	300	300	50%	300	300	300
Account 10	1,300	100	1,210	90	7%	90	90	0
Total	8,115	--	6,685	--	--	1,430	1,510	1,370
% Reduction	--	--	--	--	--	18%	19%	17%

7.3 OVERALL IMPACT RESULTS

Impacts for summer 2004 events are calculated by utility for each event using the representative day methodology for both the 3-Day Baseline and the 10-Day Adjusted Baseline, as discussed above. Impacts are first calculated using the 3-Day Baseline and compared to the utility reported impacts for validation purposes. Impacts based on the 3-Day Baseline are then compared to impacts based on the preferred 10-Day Adjusted Baseline (preference based on the findings from the baseline analysis in Section 6), and the differences are discussed. Finally, we present an estimate[8] of the demand reduction each program achieved for the summer 2004, along with an assessment of the reliability of the current planning estimate of a 15 percent load reduction.

CPP Impact Results

Exhibit 7-4 provides the comparison of the average hourly utility reported CPP impacts (in MW) and the analysis findings using the same 3-Day Baseline. Because there were a few participants for whom valid load data was not received, it was necessary to exclude them from the impact analysis. To account for this difference, a calibration adjustment was calculated that could later be applied[9] to the final impact estimates, so they would be representative of the entire participant population. This adjustment was calculated as the average hourly reduction based on the 3-Day baseline calculated for the impact analysis divided by the average hourly reduction calculated by the utilities (also using the 3-Day baseline methodology). The analysis results were found to be within 10 percent of the reported impacts for nearly every event, for each of the utilities. This resulted in calibration adjustments in the range of 90 to 100 percent for most of the events. There were a few instances where the 3-Day Baseline estimate calculated for a particular account for the impact analysis differed slightly from that calculated by the utility, thus resulting in a calibration ratio slightly greater than 100 percent. This most likely is caused by changes made to the interval data during the VEE process[10]. In these situation where the ratio was greater than 100 percent, adjustment was not applied since the point of the adjustment is to increase the final estimate to account for missing participants rather than to decrease the final estimates based on possible data inaccuracy that existed in the utility data prior to the data verification process (which the utilities based their preliminary impact estimates upon).

The average hourly CPP impacts reported by the utility for SCE and SDG&E were based on the sum of all positive and negative impacts for each event hour divided by the total number of event hours. PG&E however, appeared to have summed only those hours reporting positive impacts which explains the larger difference between the Utility reported and Analysis calculated average hourly reductions presented in the exhibit below. The calibration adjustments presented in the table for PG&E were calculated using the sum of the positive

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[8] It is important to note that this estimate is for what these programs achieved for the summer of 2004 and should not be extrapolated to assume impact estimates for future program years without significant caveats.

[9] Final impact estimates are adjusted by dividing them by the calibration adjustment.

[10] Each of the utilities provided interval meter data to QC for the impact analysis after it had gone through the VEE'd process. The results provided to QC for comparison purposes were mostly preliminary results and not necessarily based on VEE'd data.

impacts in order to create a more accurate adjustment. For the analysis however, the sum of all positive and negative hourly impacts were used for all utilities to ensure consistency in the final results. Because CPP is a rate that is charged to all participants for each event, as opposed to the DBP program for which participation in a specific event is optional, this method of impact calculation is believed to be an accurate calculation of total program impacts across all CPP participants.

Exhibit 7-4
Comparison of Utility Reported CPP Demand Reduction and Analysis Findings[11]

			Average Hourly Reduction in MW's				
Utility	**Event #**	**Event Date**	**N**	**Utility Calculated 3-Day Baseline**	**N**	**Evaluation Calculated 3-Day Baseline**	**Calibration Adjustment****
PG&E	CPP #1	08/27/04	112	8.3	109	5.4	89%
	CPP #2	09/08/04	119	7.4	116	5.0	102%
	CPP #3	09/09/04	119	9.0	115	7.7	98%
	CPP #4	09/10/04	94	11.7	91	11.1	98%
	CPP #5	10/13/04	129	8.5	n/a	n/a	n/a
SDG&E	CPP #1	07/13/04	41	4.4	40	3.7	85%
	CPP #2	07/22/04	42	4.1	41	3.9	97%
	CPP #3	08/11/04	47	3.6	46	3.6	98%
	CPP #4	09/01/04	47	4.5	46	4.4	98%
	CPP #5	09/08/04	47	4.9	46	4.0	83%
	CPP #6	09/23/04	48	4.9	46	4.3	88%
SCE	CPP #1	07/14/04	8	0.8	6	0.7	87%
	CPP #2	07/22/04	7	0.9	7	0.9	99%
	CPP #3	08/11/04	8	1.0	7	0.9	91%
	CPP #4	08/12/04	8	1.0	7	0.9	91%
	CPP #5	09/03/04	8	1.3	7	1.2	93%
	CPP #6	09/09/04	8	0.9	7	0.8	91%
	CPP #7	09/10/04	8	1.2	7	1.1	92%
	CPP #8	09/13/04	8	1.2	7	1.1	93%
	CPP #9	09/14/04	8	1.2	7	1.1	91%
	CPP #10	09/23/04	7	1.0	7	0.9	90%
	CPP #11	09/24/04	7	1.3	7	1.1	90%
	CPP #12	09/27/04	8	1.2	7	1.0	89%

* Includes all positive and negative impacts on an hourly basis hour
** PG&E Calibration Adjustment based on only positive impacts

Exhibit 7-5 compares the analysis estimates of demand reduction for the CPP using the 3-Day Baseline and 10-Day Adjusted Baselines.

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[11] Because PG&E calculated the average hourly reductions for CPP as the sum of the positive hourly impacts, the calibration adjustments for PG&E was calculated as the ratio between the utility and analysis estimates based solely on the positive hourly impacts. For this reason the analysis calculated average hourly impacts shown in the table show a larger difference than is explained by the calibration adjustments.

Exhibit 7-5
Comparison of 3-Day and 10-Day Adjusted CPP Demand Reduction Estimates

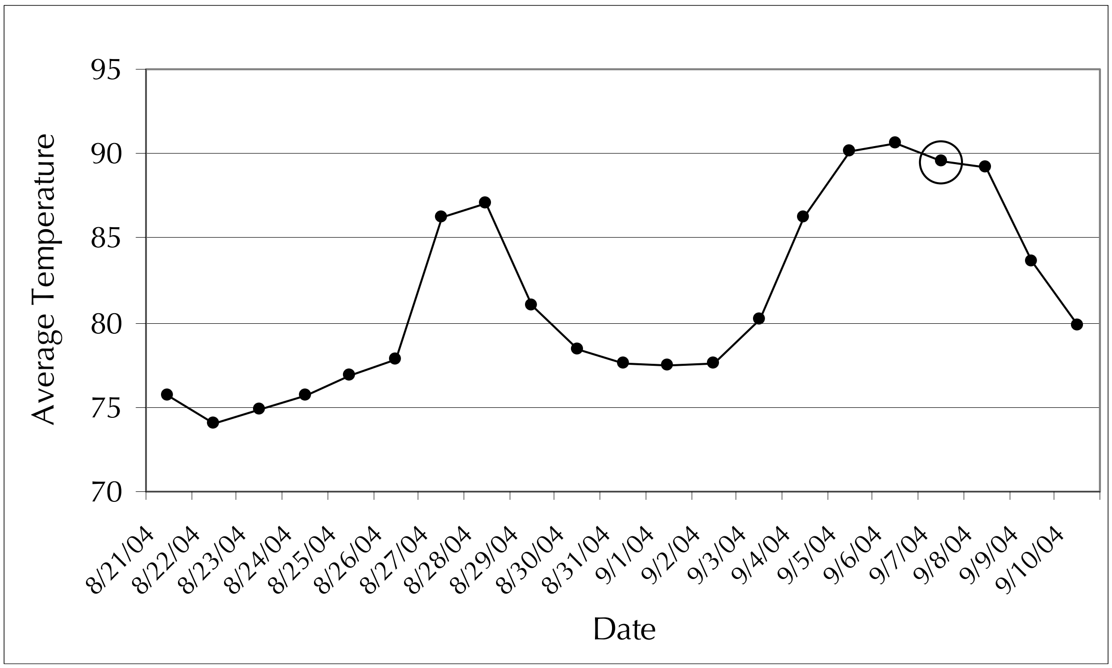
Utility	Event #	Event Date	N	3-Day Baseline	10-Day Adjusted Baseline (Prior-Day)	% Difference from 3-Day
			Evaluation Calculated Impacts in MW's			
PG&E	CPP #1	08/27/04	109	5.4	2.1	-61%
	CPP #2	09/08/04	116	5.0	7.4	48%
	CPP #3	09/09/04	115	7.7	10.1	30%
	CPP #4	09/10/04	91	11.1	13.1	18%
SDG&E	CPP - #1	07/13/04	40	3.7	1.2	-67%
	CPP - #2	07/22/04	41	3.9	2.9	-25%
	CPP - #3	08/11/04	46	3.6	2.5	-31%
	CPP - #4	09/01/04	46	4.4	2.6	-41%
	CPP - #5	09/08/04	46	4.0	1.8	-56%
	CPP - #6	09/23/04	46	4.3	2.9	-33%
SCE	CPP #1	07/14/04	6	0.7	0.7	-4%
	CPP #2	07/22/04	7	0.9	0.8	-11%
	CPP #3	08/11/04	7	0.9	0.8	-14%
	CPP #4	08/12/04	7	0.9	0.8	-15%
	CPP #5	09/03/04	7	1.2	0.9	-21%
	CPP #6	09/09/04	7	0.8	0.7	-15%
	CPP #7	09/10/04	7	1.1	1.0	-11%
	CPP #8	09/13/04	7	1.1	1.0	-11%
	CPP #9	09/14/04	7	1.1	1.0	-11%
	CPP #10	09/23/04	7	0.9	0.7	-19%
	CPP #11	09/24/04	7	1.1	1.0	-15%
	CPP #12	09/27/04	7	1.0	0.8	-17%

* Includes all positive and negative impacts on an hourly basis hour

Recall from Chapter 6, that the 3-Day Baseline methodology was found to have the most significant upward bias of all the baseline methodologies analyzed. This result holds true for nearly every CPP event analyzed, except for three consecutive CPP events for PG&E (events #2 through #4). Aside from these three PG&E event days, the 10-Day Adjusted Baseline tended to estimate impacts that were 25 to 67 percent lower across the 6 SDG&E events, 4 to 21 percent lower across the 12 SCE events, and 61 percent lower for the additional PG&E event.

Regarding the three PG&E events where the impact based on the 10-Day Adjusted Baseline exceeded the impact based on the 3-Day Baseline, these three events occurred on consecutive days, and all utilized the same "prior" day to develop the adjustment factor (since event days are excluded from the selection of the most recent "similar" days). There were two characteristics of this prior day (September 7th) that may have led the 10-Day Adjusted Baseline to produce higher impact estimates than the 3-Day Baseline methodology. The first was that September 7th was the Tuesday following Labor Day (a three day holiday weekend) and loads on this day were higher than average across a large portion of the participants. In addition, it also happened to be an extreme temperature day in comparison to two of the following three event days (9/9 and 9/10) that had increasingly lower temperatures. The average daily temperature across the PG&E CPP participants for the three consecutive CPP event days (9/8 – 9/10) as well as the 2 weeks prior to these events (from which the 10 previous days used for the 10-Day Adjusted and the 3-Day baselines were selected) are provided in Exhibit 7-6 (the 9/7 prior day is circled).

Exhibit 7-6
Mean Temperature Across the PG&E CPP Participants in the Days Prior to the Three Consecutive CPP Events (September 8th, 9th and 10th)



Given the similarity in weather between the prior day on 9/7 and the 9/8 CPP #2 event day, we might expect a reliable estimate using the 10-Day Adjusted Baseline. However, because 9/7 was the day after the Labor Day holiday, one participant may have been significantly affected, as shown in Exhibit 7-7 below, which presents the distribution of the individual CPP hourly impacts for all PG&E participants on the 9/8 event[12].

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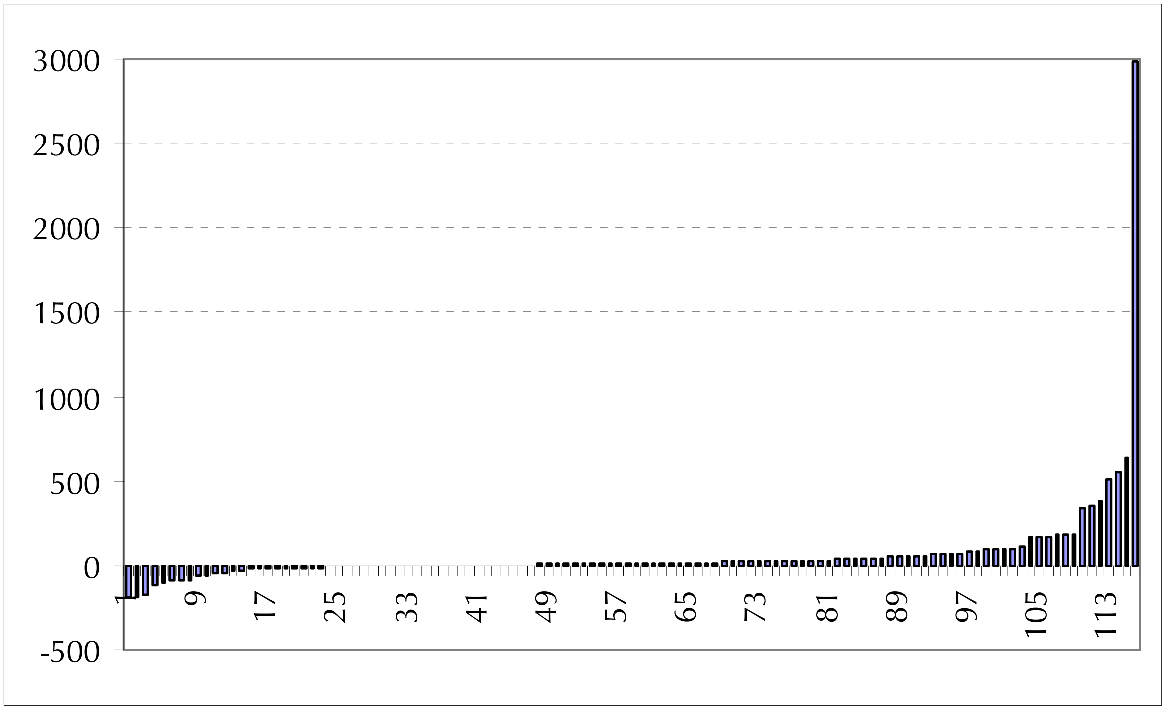
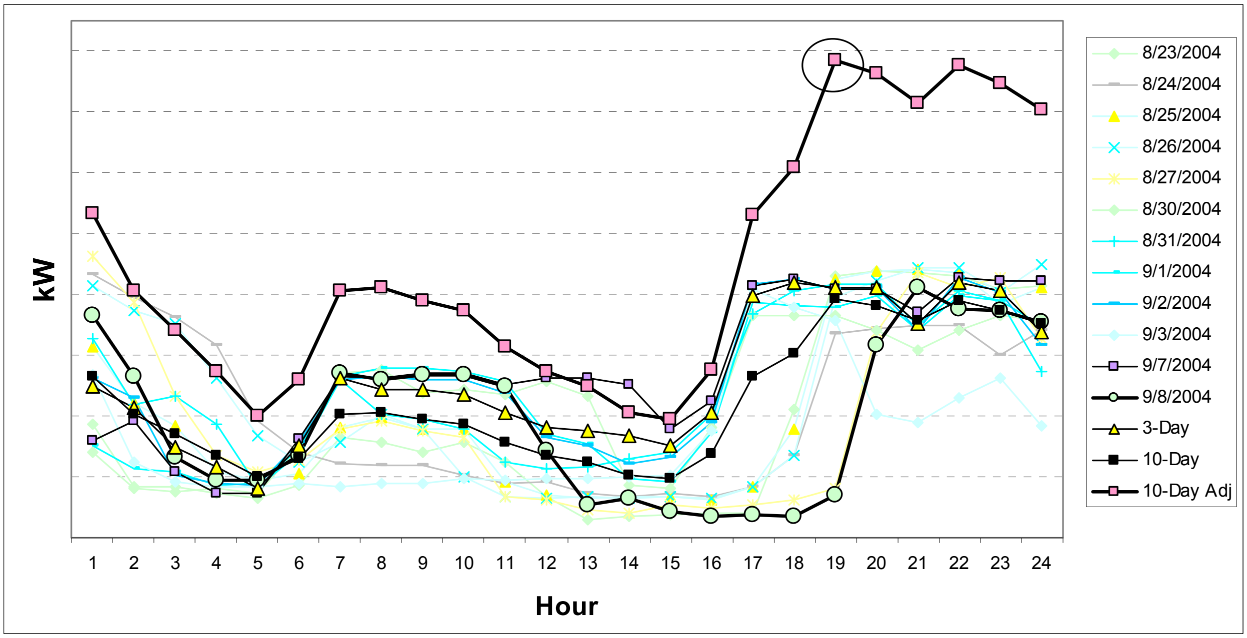
[12] Distributions of individual hourly impacts based on the 3-Day and 10-Day adjusted baselines for all CPP and DBP events for each of the three utilities are included in Appendix G.1.

Exhibit 7-7
Distribution of CPP Hourly Impacts Across Participants for PG&E 9/8 Event
10-Day Adjusted Baseline (kW differences)



One customer makes up 35 percent of the total positive impact for this event. The impact distributions for the 9/9 and 9/10 events look nearly identical, which are based on the same 9/7 prior day adjustment. Exhibit 7-8 illustrates the impact the scalar adjustment (developed from the prior day adjustment) has on this customer. This exhibit displays the daily load shapes during the 10 days prior to the event, as well as the 3-Day Baseline, 10-Day Adjusted Baseline and the actual load shape on the event day for this customer. Clearly, the significantly higher 10-Day Adjusted Baseline was overstated as a result of the adjustment factor (in particular see circled hour on 10-Day Adjusted Baseline load shape).

Exhibit 7-8
Daily Load Shapes Associated with a Single PG&E Customer for the 10 Days Preceding the September 8th CPP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates



Overall, although the differences between the impacts associated with the 3-Day Baseline and the 10-Day Adjusted Baseline presented in Exhibit 7-5 look large, the majority of the difference is explained by the bias in the 3-Day Baseline approach. As discussed in Chapter 6, the regression coefficient for the CPP 3-Day Baseline was 0.93, indicating the approach was biased upward by about 7 percent, compared to a coefficient of 0.98 for the 10-Day Adjusted approach. Although the difference in the two methods is only 5 percent, a small bias on load (or level) can translate into a very large bias on impact (or a difference). For example, for a program that saves 15 percent, a difference of 5 percent on load equates to a 33 percent difference on an impact estimate. Furthermore, the smaller the expected impact, the larger this bias effect will have on the impact.

Exhibit 7-9 presents the demand reductions resulting from each of the CPP events as a percentage of the estimated load for both the 3-Day Baseline and 10-Day Adjusted Baseline approaches. For PG&E, the one CPP event not effected by the extreme weather day after the holiday, resulted in an impact of 6 percent based on the 3-Day Baseline, and only 2 percent based on the 10-Day Adjusted Baseline; a difference of only 4 percent relative to load, but a 61 percent difference on impact. This 4 percent difference relative to load is likely to be primarily attributable to the bias inherent in the 3-Day Baseline approach.

Exhibit 7-9
Comparison of 3-Day and 10-Day Adjusted CPP Demand Reduction Estimates Expressed as a Percentage of Load

				3-Day Baseline			10-Day Adjusted Baseline		
Utility	**Event #**	**Event Date**	**N**	**Average Hourly Reduction (MW's)**	**Estimated Load**	**% Reduction**	**Average Hourly Reduction (MW's)**	**Estimated Load**	**% Reduction**
PG&E	CPP #1	08/27/04	109	5.4	90	6%	2.1	87	2%
	CPP #2	09/08/04	116	5.0	101	5%	7.4	103	7%
	CPP #3	09/09/04	115	7.7	100	8%	10.1	102	10%
	CPP #4	09/10/04	91	11.1	81	14%	13.1	83	16%
SDG&E	CPP - #1	07/13/04	40	3.7	15.1	25%	1.2	12.6	10%
	CPP - #2	07/22/04	41	3.9	17.0	23%	2.9	15.9	19%
	CPP - #3	08/11/04	46	3.6	17.5	20%	2.5	16.4	15%
	CPP - #4	09/01/04	46	4.4	17.8	25%	2.6	15.9	16%
	CPP - #5	09/08/04	46	4.0	17.5	23%	1.8	15.1	12%
	CPP - #6	09/23/04	46	4.3	17.0	25%	2.9	15.4	19%
SCE	CPP #1	07/14/04	6	0.7	1.6	43%	0.7	1.6	42%
	CPP #2	07/22/04	7	0.9	1.7	53%	0.8	1.6	50%
	CPP #3	08/11/04	7	0.9	1.6	59%	0.8	1.4	55%
	CPP #4	08/12/04	7	0.9	1.6	57%	0.8	1.4	53%
	CPP #5	09/03/04	7	1.2	1.7	71%	0.9	1.4	66%
	CPP #6	09/09/04	7	0.8	1.7	51%	0.7	1.5	47%
	CPP #7	09/10/04	7	1.1	1.7	68%	1.0	1.5	66%
	CPP #8	09/13/04	7	1.1	1.7	64%	1.0	1.5	62%
	CPP #9	09/14/04	7	1.1	1.7	65%	1.0	1.5	62%
	CPP #10	09/23/04	7	0.9	1.7	53%	0.7	1.6	48%
	CPP #11	09/24/04	7	1.1	1.7	65%	1.0	1.6	61%
	CPP #12	09/27/04	7	1.0	1.7	59%	0.8	1.6	54%

* Includes all positive and negative impacts on an hourly basis hour

For SDG&E, the demand reduction is fairly stable over the six event days, ranging from 20 to 25 percent of load based on the 3-Day Baseline, and ranging from 10 to 19 percent of load based on the 10-Day Adjusted Baseline. The differences between the two methods when expressed as a percentage of load are within 5 to 8 percent of each other for four of the six events, and no more than 15 percent over all six events.

Also stable are the SCE results; however, these results are based on a small sample of just 8 customers, which are driven primarily by a single customer[13]. Nevertheless, the demand reduction across the 12 event days ranges from 43 to 71 percent of load based on the 3-Day Baseline, and ranges from 42 to 66 percent of load based on the 10-Day Adjusted Baseline. The differences between the two methods when expressed as a percentage of load are within 1 to 5 percent of each other across all events.

[13]In total SCE had only 8 accounts signed up for the CPP program, three of which had loads for most of the summer that were between 0 and 50kW. Three other customers had loads in the 200 kW range, however, showed little to no reduction for the majority of the events. This left two customers remaining, both of which appeared to be actively participating in the program. One of these customers who had an average load around 300kW routinely curtailed approximately 25-35 percent of their load for the CPP events and the other customer (who is the primary driver of the overall results) had an average load just under 1 MW and regularly shed 80-90 percent of this load for the CPP events.

Across all CPP event days and all utilities, the impact estimates for the 3-Day and 10-Day Adjusted methods, when expressed as a percentage of load, tend to differ by 4 to 8 percent in most instances, consistent with the expected bias introduced by the 3-Day approach as shown in Chapter 6.

Exhibits 7-10 through 7-12 presents the distribution of individual customer impacts based on the 10-Day Adjusted Baseline, as a percent of their total load over all CPP events analyzed for PG&E, SDG&E, and SCE respectively (negative impacts were truncated at –100 percent for presentation purposes).

Exhibit 7-10
Distribution of Customer Impacts (as a Percent of Total Load) Over All CPP Events for PG&E
Based on 10-Day Adjusted Baseline
91 to 116 Customers, across 4 Events

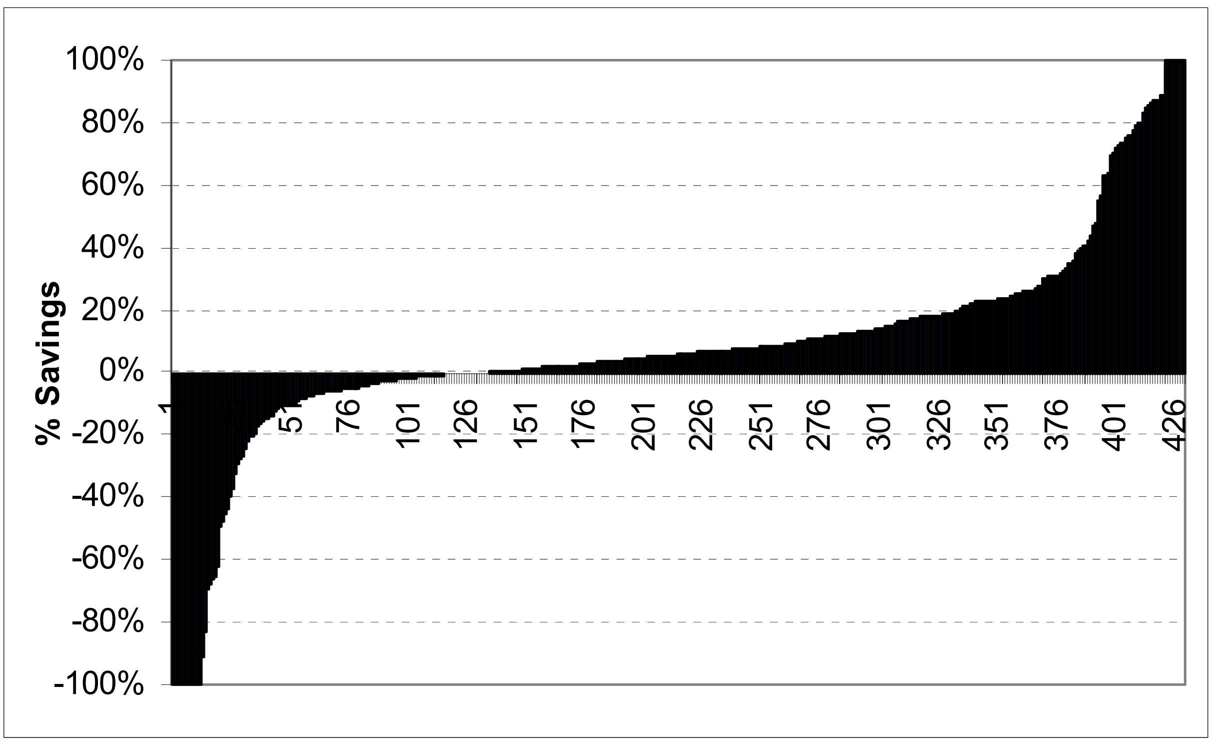


Exhibit 7-11
Distribution of Customer Impacts (as a Percent of Total Load)
Over All CPP Events for SDG&E
Based on 10-Day Adjusted Baseline
40 to 46 Customers, across 6 Events

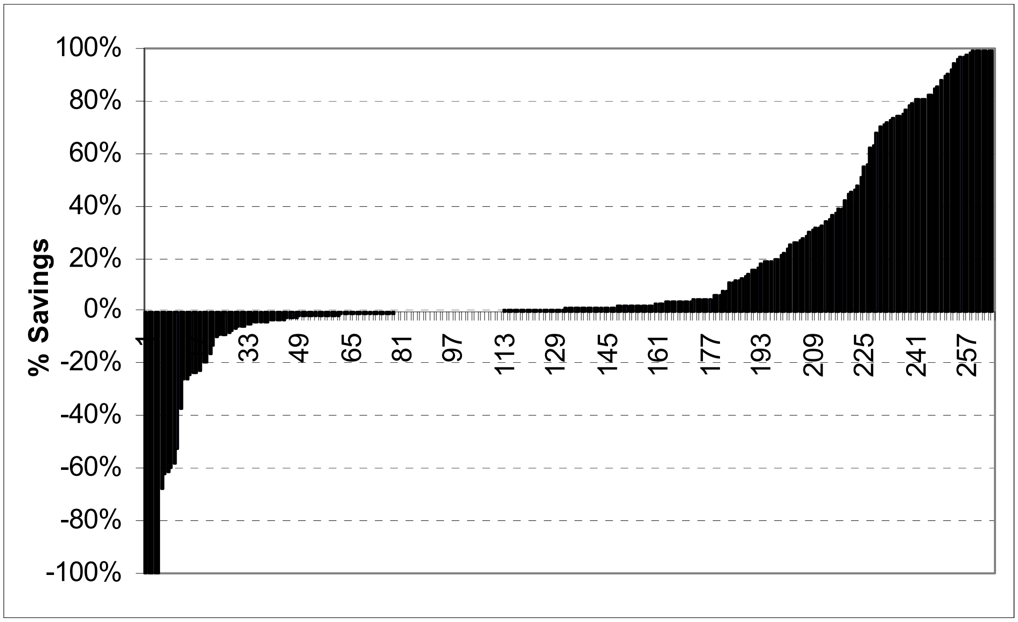
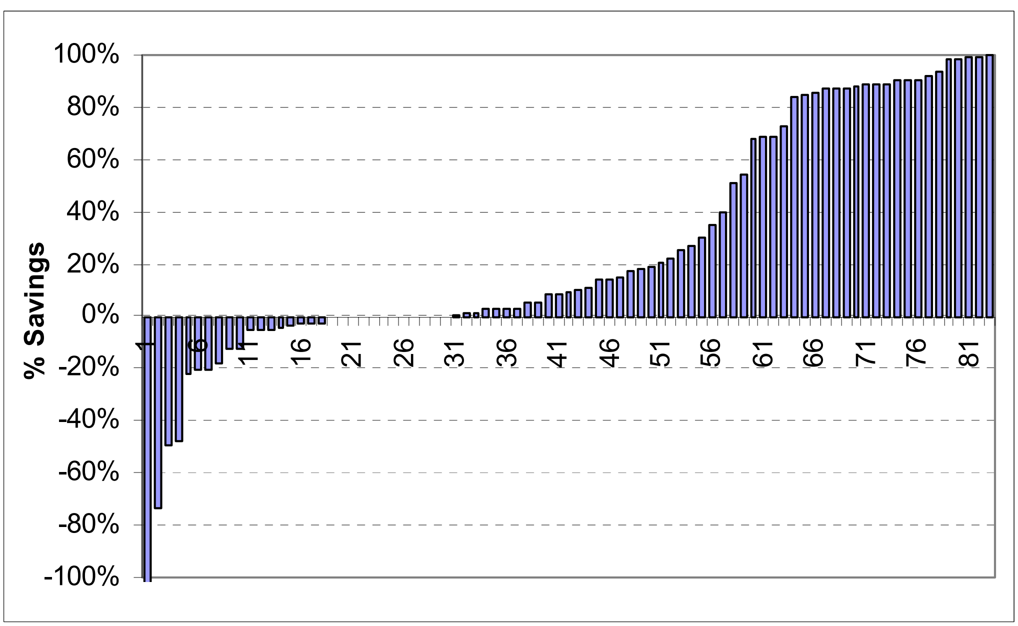


Exhibit 7-12
Distribution of Customer Impacts (as a Percent of Total Load) Over All CPP Events for SCE
Based on 10-Day Adjusted Baseline
6 to 7 Customers, across 12 Events



Based on the results presented above, it is difficult to identify a reliable estimate that can be used prospectively to forecast expected savings based on participation levels. For CPP events, as shown in Exhibit 7-9, impacts ranged from 2 percent to 16 percent of load for PG&E, 10 percent to 19 percent for SDG&E, and 42 percent to 66 percent for SCE. Its important to note that the high load for SCE is primarily driven by a single participant, whereas the PG&E and SDG&E results are based on population sizes of up to 119 and 48 participants, respectively.

Shown in Exhibit 7-13 are the estimated load impacts, presented as an average hourly MW demand reduction aggregated over the CPP population, and averaged across all CPP events, except for PG&E. For PG&E, only the first two CPP events are used to develop the average because it is felt that the results for the third and fourth CPP events are unreliable due to using a prior day that has significantly higher temperature, as shown in Exhibit 7-6. Also shown is the estimated average hourly load, and the hourly impact expressed as a percentage of load. Finally, the distributions of the average hourly impacts across all event days (except for PG&E, which is based on the first two event days) are summarized in Exhibit 7-13, presenting the median, and the 25th and 75th percentile.

The IOUs are currently using an impact estimate for CPP that is 15 percent of load, which is reasonable for SDG&E based on the results presented above. As shown in Exhibit 7-13, the average impact using the 10-Day Adjusted Baseline across six CPP events is 15 percent. Furthermore, the distribution of impacts for all SDG&E participants across the 6 events has an inter-quartile range (25th percentile to the 75th percentile) of –1 percent to 22 percent, which contains 15 percent.

Exhibit 7-13
Final CPP Demand Reduction by Utility[14]
Based on 10-Day Adjusted Baseline
MW Load Impact and Distribution of Reduction as Percentage of Load

		Average Hourly Reduction - 10-Day Adjusted Baseline					
		Average Hourly Reduction and Baseline (MW's)			Distribution of Individual Percent Reduction Impacts		
Utility	CPP Events	Estimated Impact	Estimated Load	Percent Reduction	Median	25th Percentile	75th Percentile
PG&E	#1 & #2	4.9	100	5%	1%	-5%	9%
SDG&E	#1 - #6	2.5	16.7	15%	1%	-1%	22%
SCE*	#1 - #12	0.9	1.7	55%	9%	0%	73%

* SCE numbers based on 7 accounts

[14] It is important to note that the SCE CPP percent reduction reported in this exhibit is primarily being driven by a single customer. As mentioned earlier, in total SCE had only 8 accounts signed up for the CPP program, one of which is the primary driver of the overall results, who had an average load just under 1 MW and regularly shed 80-90 percent of this load for the CPP events.

For SCE, however, it is difficult to assess if the 15 percent value currently used by the IOUs is appropriate due to the small number of participants in the program. Although the impact is estimated to be 55 percent of load, this value is driven primarily by a single customer. The median impact is 9 percent and the inter-quartile range is zero to 73 percent. Therefore, the value of 15 percent is likely a better value to be using going forward for planning purposes than 55 percent.

For PG&E, the 15 percent is on the higher end of what might be expected based on the results presented above. The mean impact is 5 percent of load based on the first two event days, and even if all four event days were used (of which the latter two are believed to be overstated), the mean impact is 9 percent. The median impact is 1 percent of load, with an inter-quartile range of –5 percent to 9 percent, which does not contain 15 percent (however, including all four event days, the inter-quartile range is -1 percent to 18 percent).

However, given the small number of event days, the influence of some large customers over some IOU-specific results, and the weather patterns on and surrounding some of the event days, we cannot reject the a priori estimate of 15 percent, particularly since the mix of customer types could change significantly as new customers participate.

DBP Impact Results

Exhibit 7-14 provides the comparison of the utility reported DBP impacts and the analysis findings using the 3-Day Baseline. Again, similar to what was discussed above for CPP, the lack of valid load data for a few of the participants and the slight differences in the 3-Day baselines that resulted from the VEE'd versus non-VEE'd data, it was necessary to calculate a calibration adjustment that could be applied to the final impact estimates to make them representative of the entire participant population. As mentioned prior for CPP, adjustments greater than 100 percent were not used to decrease the final impact estimates. For all of the DBP events the analysis results were found to be within 3 percent of the reported impacts, except for the second SCE DBP event for which load data for 6 of the reported 30 bidders was not provided for the analysis. For each of the DBP events, positive impacts were summed for all of the bidding customers to determine the estimated event impact[15]

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[15] See Appendix G.2 for an exhibit showing different impact estimates resulting from the three alternatives for counting impacts. This is an area where additional research would be beneficial but was not included as part of this analysis due to the degree of uncertainty that existed around the impact estimates already due to the number of program participants and the limited non-test events.

Exhibit 7-14
Comparison of Utility Reported DBP Demand Reduction and Analysis Findings

			Average Hourly Reduction in MW's							
Event Details			Utility Reported				Analysis Findings			
Utility	Event #	Event Date	N	Bid	3-Day Baseline	Hourly Bid Reduction	N	Bid	3-Day Baseline	Calibration Adjustment
SDG&E	DBP #1	05/03/04	25	6	0.6	1.1	19	6	0.6	100%
	DBP #2	06/30/04	37	9	1.1	1.1	28	9	1.1	103%
	DBP #3	09/07/04	40	7	1.1	1	33	7	1.1	100%
SCE	DBP #1	06/09/04	465	21	17.8	13.6	465	21	17.8	100%
	DBP #2	09/23/04	542	30	25.1	18.5	492	24	22.6	90%
PG&E	DBP #1	07/26/04	78	n/a	26.4	n/a	78	n/a	26.9	102%

* Includes all positive impacts from bidders on an hourly basis hour

Exhibit 7-15 compares the analysis estimates of demand reduction for the DBP using the 3-Day Baseline and 10-Day Adjusted Baselines. Again, the 3-Day Baseline methodology provided higher estimates of demand reduction: 10 to 13 percent higher for SDG&E, 34 to 75 percent higher for SCE, and 44 percent higher for PG&E.

Exhibit 7-15
Comparison of 3-Day and 10-Day Adjusted DBP Demand Reduction Estimates

			Evaluation Calculated Impacts in MW's				
Utility	Event #	Event Date	N	Bid	3-Day Baseline	10-Day Adjusted Baseline (Same-Day)	% Difference from 3-Day
SDG&E	DBP #1	05/03/04	19	6	0.6	0.5	-13%
	DBP #2	06/30/04	28	9	1.1	1.0	-11%
	DBP #3	09/07/04	33	7	1.1	1.0	-10%
SCE	DBP #1	06/09/04	465	21	17.8	11.7	-34%
	DBP #2	09/23/04	492	24	22.6	5.6	-75%
PG&E	DBP #1	07/26/04	78	n/a	26.9	15.1	-44%

* Includes all positive impacts from bidders on an hourly basis hour

Again, a large component of the difference in the impact estimates for the 3-Day and 10-Day Adjusted methods, when expressed as a percentage of load, can be explained by the bias in the 3-Day approach. As shown in Exhibit 7-16, the demand reduction is fairly stable over the three event days for SDG&E, ranging from 22 to 29 percent of load based on the 3-Day Baseline, and ranging from 19 to 28 percent of load based on the 10-Day Adjusted Baseline. The differences between the two methods when expressed as a percentage of load are within 2 to 3 percent for all three events.

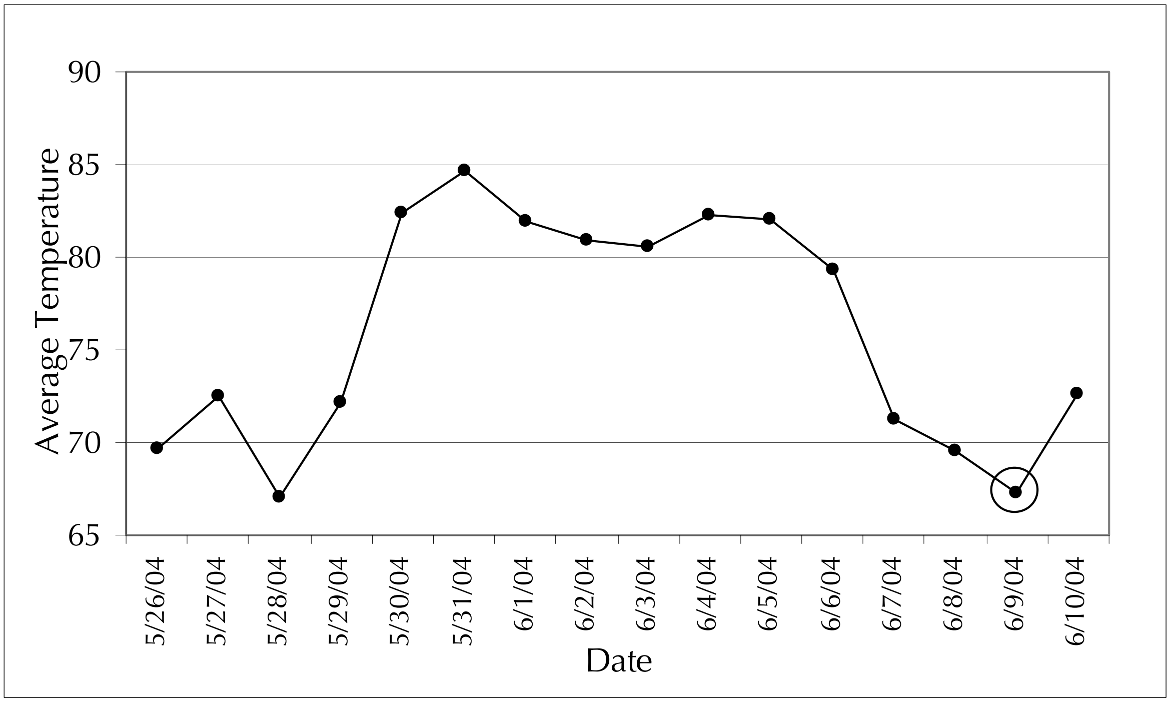
Exhibit 7-16
Comparison of 3-Day and 10-Day Adjusted DBP Demand Reduction Estimates
Expressed as a Percentage of Load

					3-Day Baseline			10-Day Adjusted Baseline		
Utility	**Event #**	**Event Date**	**N**	**Bid**	**Average Hourly Reduction (MW's)**	**Estimated Load**	**% Reduction**	**Average Hourly Reduction (MW's)**	**Estimated Load**	**% Reduction**
SDG&E	DBP #1	05/03/04	19	6	0.6	2.8	22%	0.5	2.8	19%
	DBP #2	06/30/04	28	9	1.1	3.9	28%	1.0	3.8	26%
	DBP #3	09/07/04	33	7	1.1	3.6	29%	1.0	3.5	28%
SCE	DBP #1	06/09/04	465	21	17.8	30	59%	11.7	23.4	50%
	DBP #2	09/23/04	492	24	22.6	87	26%	5.6	67.6	8%
PG&E	DBP #1	07/26/04	78	n/a	26.9	105	26%	15.1	91.3	17%

* Includes all positive impacts from bidders on an hourly basis hour

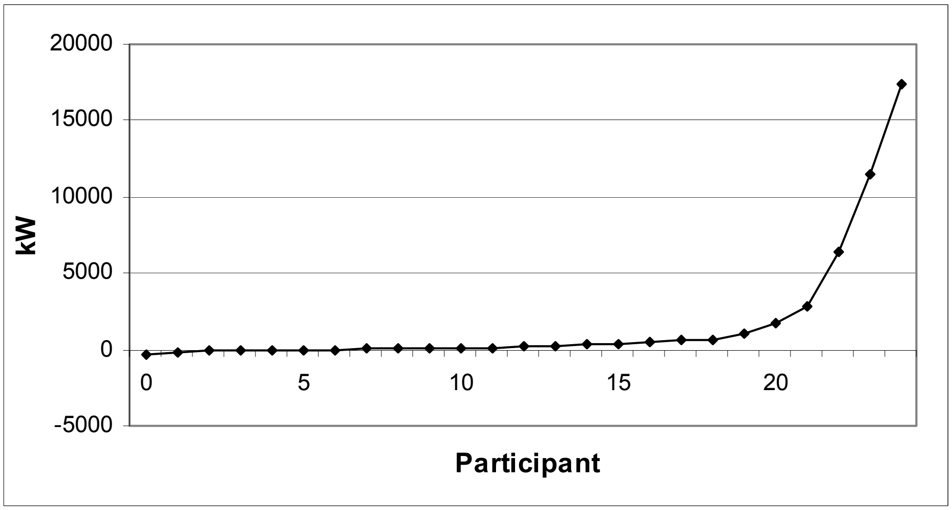
For SCE, the results are very different across the two event days. For the first event day, the difference in impacts is 9 percent of load, however the savings is much larger: the impact based on the 3-Day approach is 59 percent of the load compared to 50 percent based on the 10-Day Adjusted approach. For the second event day, the savings, as expressed as a percentage of load, decreased significantly, but the differences between the two methods doubled to 18 percent of load: the impact based on the 3-Day approach is 26 percent of the load compared to only 8 percent based on the 10-Day Adjusted approach. One issue with the first event, which occurred on June 9th, is that the average temperature in the Edison territory was relatively low (68 degrees averaged across the weather stations associated with the DBP participants who entered a bid). During the week preceding this event, temperature hit the low to mid 80's on multiple days. Therefore, the 3-Day Baseline Approach is likely to have been significantly biased upwards due to this weather effect. The average temperatures for the days surrounding the June 9th event (circled) are presented in Exhibit 7-17.

Exhibit 7-17
Mean Temperature for SCE DBP Participants in the Days Prior to the First DBP Event (June 9th)



Upon visual inspection of the participants' load shapes on days leading up to and including the second SCE event day (September 23rd), five outliers were identified as having significantly different 3-Day and 10-Day Adjusted Baselines, and were also major contributors to the overall average demand reduction estimate. Exhibit 7-18 below displays the cumulative summation of the differences that existed between the 3-Day baseline estimate and the 10-Day baseline estimate. As shown, there are 5 points, each representing an individual customer, that account for the majority of the differences between these two methods.

Exhibit 7-18
Cumulative Differences Between the 3-Day and 10-Day Adjusted Baselines for the SCE September 23ed DBP Event



A display of the daily load shapes during the 10 days prior to the event, as well as the 3-Day Baseline, 10-Day Adjusted Baseline and the actual load shape on the event day for two of these customers are presented in Exhibits 7-19 and 7-20.

Exhibit 7-19
Daily Load Shapes Associated with a Single SCE Customer for the 10 Days Preceding the September 23rd DBP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates

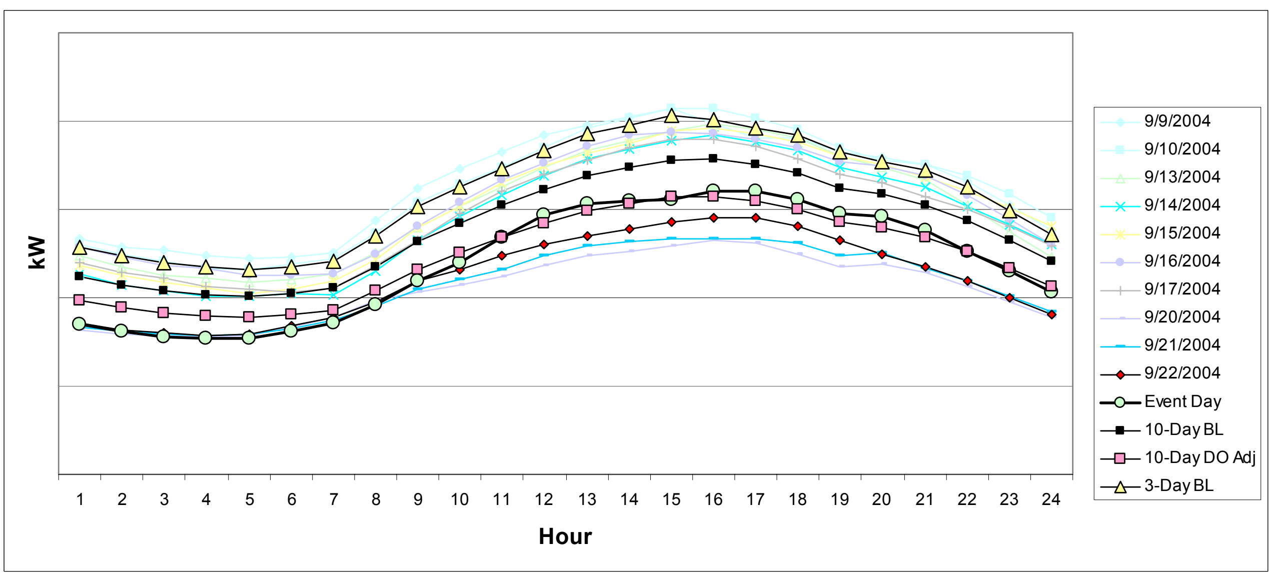


Exhibit 7-20
Daily Load Shapes Associated with a Single SCE Customer for the 10 Days Preceding the September 23rd DBP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates

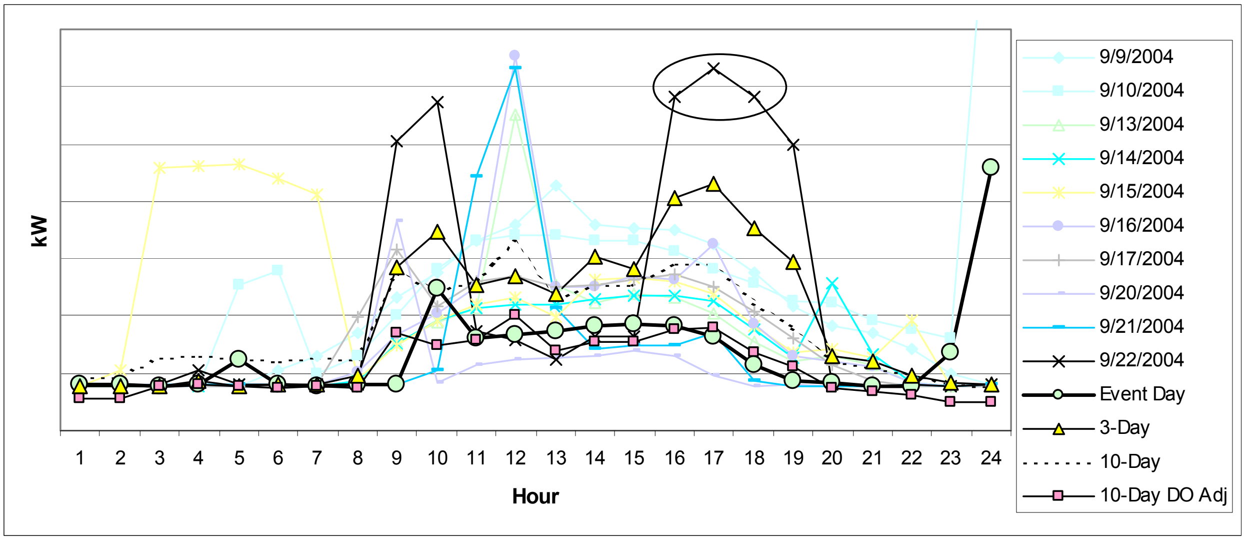
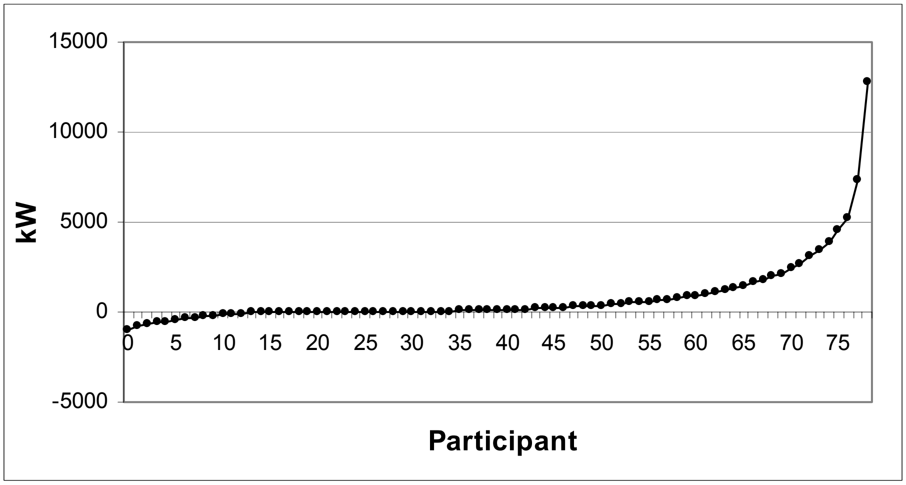


Exhibit 7-19 above illustrates how for some customers with relatively smooth load shapes the 3-Day Baseline can significantly over-estimate the customers' reduction. The customer displayed in this exhibit is a large customer and thus the magnitude of the resulting error was approximately 20 percent of the overall impact for this DBP event. This customer also only bid a 150 kW reduction an hour, significantly less than what the 3-Day showed them to have done. For this customer, this visual inspection of the load shapes resulted in a decision to continue to use the 10-Day Adjusted baseline for the final impact calculation, which is discussed in more detail below.

Exhibit 7-20, also a large customer, shows the large impact a spike (circled) in a customers load shape on one day can have on the 3-Day baseline. For this customer, this visual review resulted in a decision that the 10-Day unadjusted baseline provided a more reliable estimate of the load reduction for the event for the final impact calculation, which is discussed in more detail below.

Exhibit 7-16 above also illustrates that for the single PG&E DBP event day, a similar issue arose. For PG&E, the impact based on the 3-Day approach is 26 percent of the load compared to 17 percent based on the 10-Day Adjusted approach, a 9 percent difference. As with the SCE event day, upon visual inspection, four outliers were identified that had significant differences between their 3-Day and 10-Day Adjusted Baselines. Exhibit 7-21 displays the cumulative summation of the differences that existed between the 3-Day baseline estimate and the 10-Day baseline estimate for the single PG&E DBP Event. This exhibit, in contrast to the similar Exhibit 7-18 for SCE, has fewer points on the tail representing distinct accounts that make up the majority of the differences between the two methods.

Exhibit 7-21
Cumulative Differences between the 3-Day and 10-Day Adjusted Baselines for the PG&E July 26th DBP Event



A display of the daily load shapes during the 10 days prior to the event, as well as the 3-Day Baseline, 10-Day Adjusted Baseline and the actual load shape on the event day for two of these customers are presented in Exhibits 7-22 and 7-23.

Exhibit 7-22
Daily Load Shapes Associated with a Single PG&E Customer for the 10 Days Preceding the July 26th DBP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates

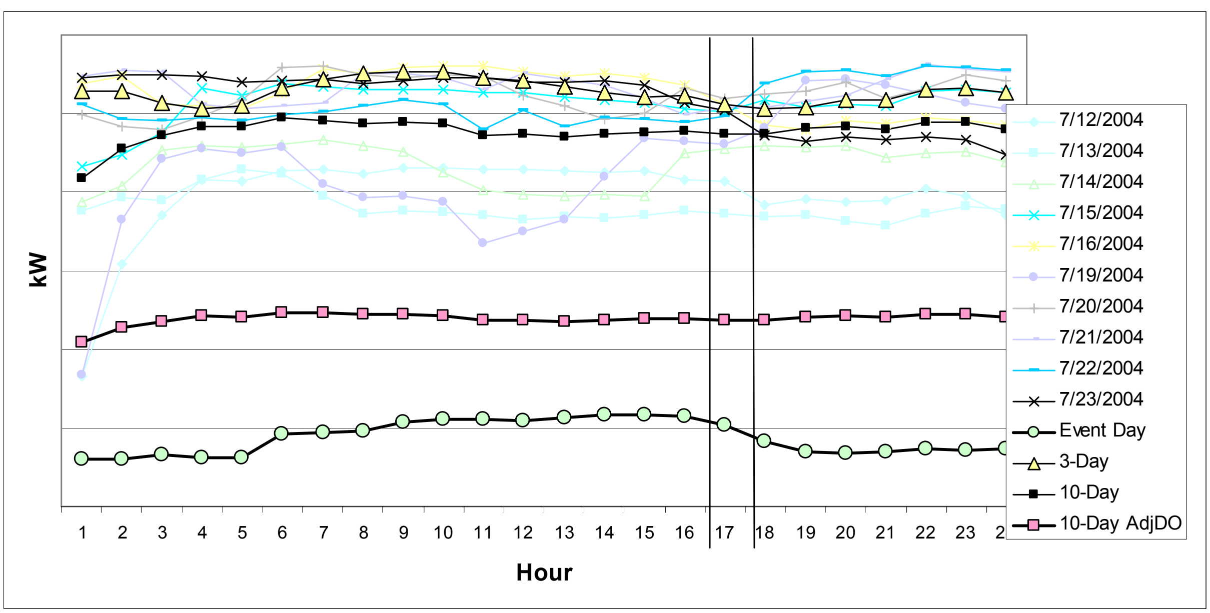


Exhibit 7-23
Daily Load Shapes Associated with a Single PG&E Customer for the 10 Days Preceding the July 26th DBP Event, the Actual Event Day and the 3-Day, 10-Day and 10-Day Adjusted Baseline Estimates

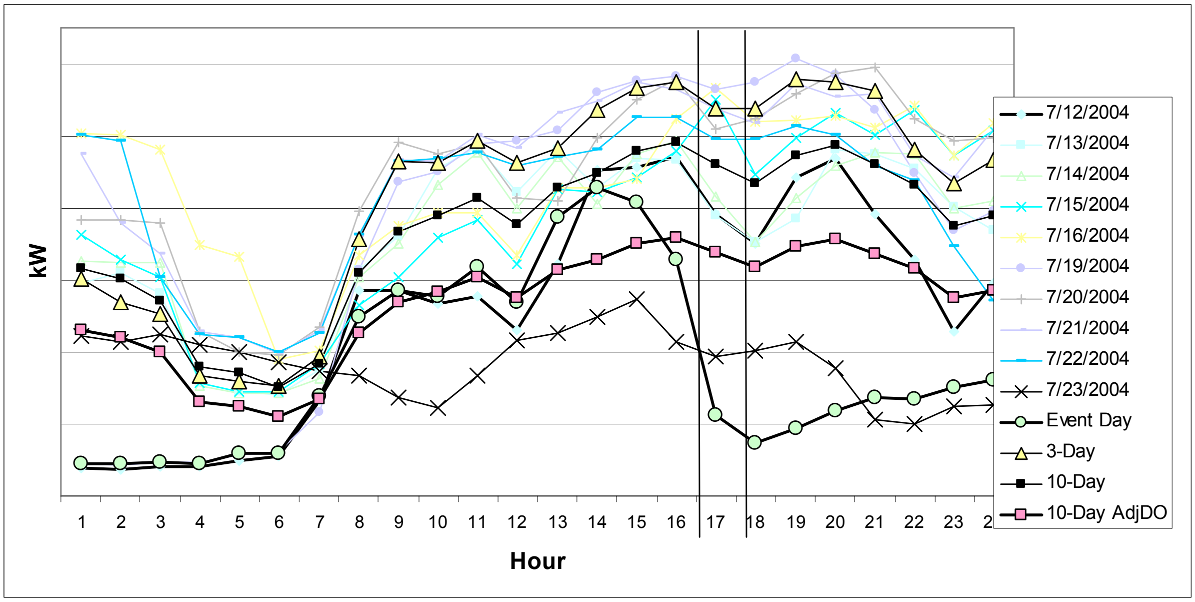


Exhibit 7-22 above provides another example of how, for some customers with relatively smooth load shapes, the 3-Day Baseline significantly over-estimates the customers' reduction. In this case the 10-Day and the 10-Day Adjusted also seem to have similar flaws, only to a lesser degree. This event fell on a Monday and as the graph displays with the faint previous 10-Day lines, the customer's load shape typically starts relatively low on a Monday morning and then ramps up during the 2nd hour of the day. The fact that this customer never started ramping up on this Monday morning introduces the question of whether this day was a planned off day for the customer, or if they received an advanced notice of the event (which was supposed to be supplied no earlier than 11 am on the day of the event). The customer displayed in this exhibit is a large customer and thus the magnitude of the resulting difference between their 3-Day Baseline and their actual load was roughly one-third of the total reported impact for the PG&E DBP Event. For this customer, the visual inspection of the load shapes resulted in a decision to continue to use the 10-Day Adjusted Baseline for the final impact calculation, which is discussed in more detail below.

Exhibit 7-23, also a large customer, shows a clear reduction in a customer's load for the DBP event, however it is very difficult to distinguish what the true baseline should be for such a customer. As a result, for this customer the visual inspection determined that the 10-Day unadjusted baseline provided a more reliable estimate, and was used in the final impact calculation, which is discussed below.

Exhibit 7-24 below presents the 3-Day Baseline and 10-Day Adjusted Baseline estimates for all bidders in these two event days for SCE and PG&E. Shown are all bidders, the outliers that were identified for each event, and all bidders with the outliers excluded. For SCE, the five outliers represented 18.1 of the 22.6 MW load reduction based on the 3-Day approach, but only

1.7 MW of the 5.6 MW load reduction based on the 10-Day Adjusted approached. When expressed as a percentage of load, the demand reduction was 25 percent based on the 3-Day approach, and only 3 percent based on 10-Day Adjusted approach. For the remaining participants, the demand reduction was 30 percent and 28 percent, based on the 3-Day and 10-Day Adjusted approaches, respectively. Clearly, without these five outliers, the two approaches are much more consistent, as expected.

For these five outliers, a visual inspection, as described above, was made of the two weeks leading up to and including the event day, along with the 3-Day, 10-Day Adjusted and 10-Day unadjusted baselines. As discussed in Chapter 6, the 10-Day unadjusted baseline was generally found to be the lower bound among the various baseline approaches implemented. For two of these outliers, visual analysis led us to believe the 10-Day Adjusted Baseline was the most reasonable. However, for three outliers, we felt the 10-Day unadjusted baseline was more reasonable. In each of these cases, the 10-Day unadjusted baseline was *higher* than the 10-Day Adjusted Baseline.

After selecting the baseline approach believed to be most appropriate, the five outliers were found to contribute 4.6 MW, corresponding to an 8 percent reduction in load, compared to a 18.1 MW load reduction (or 25 percent of load) based on the 3-Day approach. Altogether, the combined 10-Day Baseline approach resulted in a demand reduction of 8.5 MW, corresponding to a 12 percent reduction in load, compared to a 22.6 MW load reduction (or 26 percent of load) based on the 3-Day approach.

Exhibit 7-24
Adjusted Demand Reduction Among Outliers and Resulting Program Level Impacts

			Adjustments		3-Day Baseline			10-Day Adjusted Baseline		
Utility	Event #	Event Date	Estimate Type	N	Average Hourly Reduction	Estimated Load	% Reduction	Average Hourly Reduction	Estimated Load	% Reduction
SCE	DBP #2	09/23/04	Baseline Estimate	492	22.6	87	26%	5.6	67.6	8%
			w/o Outliers	487	4.6	15	30%	3.9	14.2	28%
			Outliers Only	5	18.1	72	25%	1.7	53.5	3%
			Manual Adj	5	-	-	-	4.6	56.8	8%
			Adj. Estimate	492	-	-	-	8.5	70.9	12%
PG&E	DBP #1	07/26/04	Baseline Estimate	78	26.9	105	26%	15.1	91.3	17%
			w/o Outliers	74	12.4	86	14%	9.4	81.5	12%
			Outliers Only	4	14.6	19	76%	5.7	10	58%
			Manual Adj	4	-	-	-	6.8	11.8	58%
			Adj. Estimate	78	-	-	-	16.2	93.2	17%

* Includes all positive impacts from bidders on an hourly basis hour

For PG&E, the four outliers represented 14.6 of the 26.9 MW load reduction based on the 3-Day approach, but only 5.7 MW of the 15.1 MW load reduction based on the 10-Day Adjusted approached. When expressed as a percentage of load, the demand reduction was 76 percent based on the 3-Day approach, and 58 percent based on 10-Day Adjusted approach. For the remaining participants, the demand reduction was 14 percent and 12 percent, based on the 3-Day and 10-Day Adjusted approaches, respectively. Again, without these outliers, the two approaches are much more consistent.

As with the SCE outliers discussed above, a visual comparison was made between the two weeks leading up to and including the event day, along with the 3-Day, 10-Day Adjusted and 10-Day unadjusted baselines. For two of these outliers, we chose to use the 10-Day unadjusted as the preferred baseline approach. After selecting the baseline approach believed to be most appropriate, the four outliers were found to contribute 6.8 MW, corresponding to a 58 percent reduction in load, compared to a 14.6 MW load reduction (or 76 percent of load) based on the 3-Day approach. Altogether, the combined 10-Day Baseline approach resulted in a demand reduction of 16.2 MW, corresponding to a 17 percent reduction in load, compared to a 26.9 MW load reduction (or 26 percent of load) based on the 3-Day approach.

Exhibits 7-25 through 7-27 present the distribution of individual customer impacts based on the 10-Day Adjusted Baseline, as a percent of their total load over all DBP events analyzed for PG&E, SDG&E, and SCE respectively. For PG&E all participants are shown (negative impacts were truncated at –100 percent for presentation purposes). However, for SDG&E and SCE, only bidders are shown, and any negative impacts were set to zero.

Exhibit 7-25
Distribution of Customer Impacts (as a Percent of Total Load) Over All DBP Events for PG&E
Based on 10-Day Adjusted Baseline
78 Customers, across 1 Event
All Participants

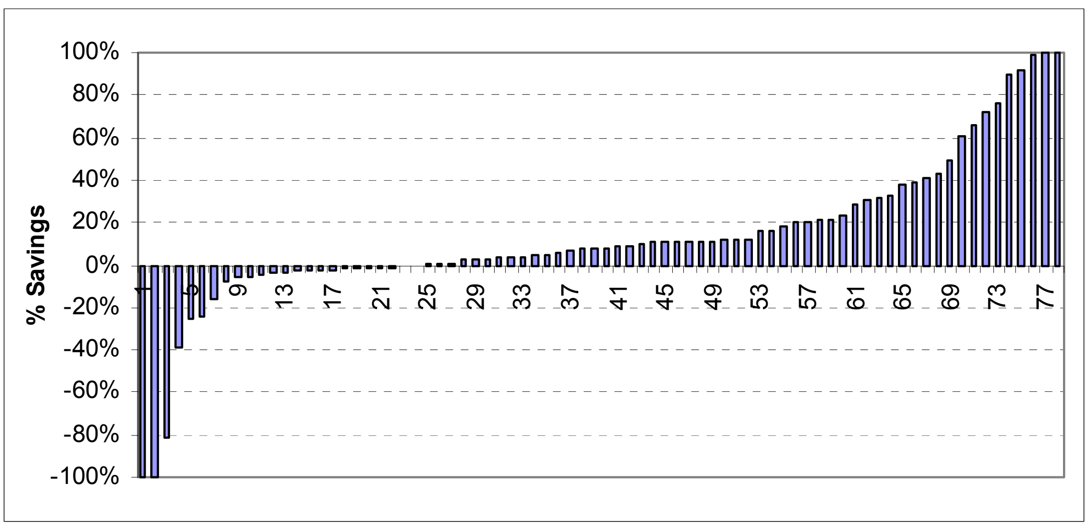


Exhibit 7-26
Distribution of Customer Impacts (as a Percent of Total Load) Over All DBP Events for SCE
Based on 10-Day Adjusted Baseline
21 to 24 Customers, across 2 Events
Bidders Only

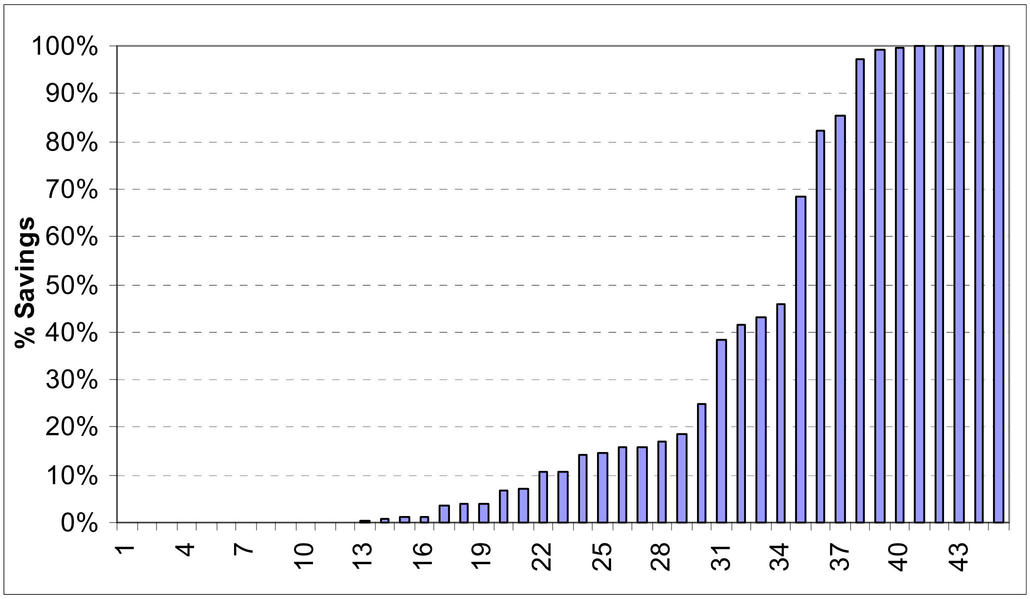
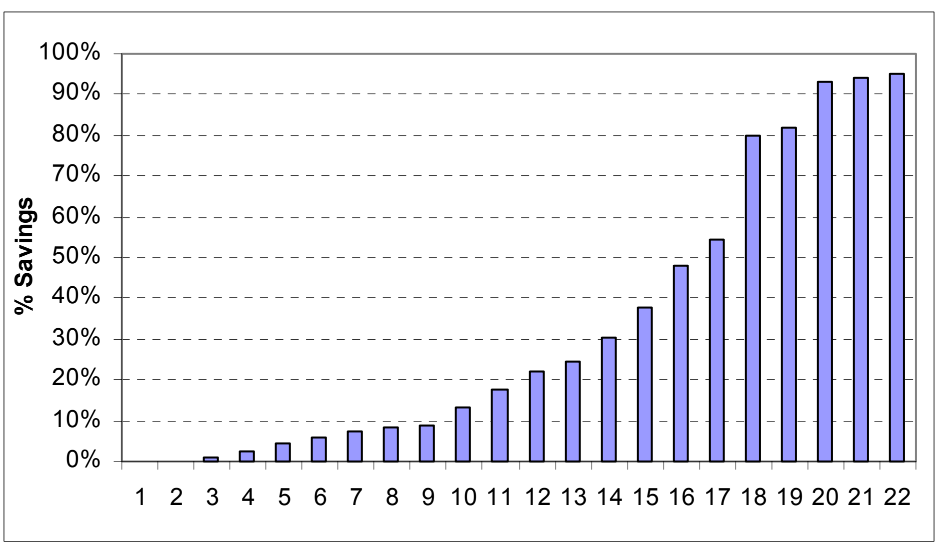


Exhibit 7-27
Distribution of Customer Impacts (as a Percent of Total Load)
Over All DBP Events for SDG&E
Based on 10-Day Adjusted Baseline
6 to 9 Customers, across 3 Events
Bidders Only



As with the CPP impacts, it is difficult to identify a reliable DBP impact estimate that can be used prospectively to forecast expected savings based on participation levels. For DBP events, as shown in Exhibits 7-16 and 7-24, the impact of the single PG&E event was 17 percent, and for all bidders in SCE and SDG&E, impacts ranged from 12 percent to 50 percent in SCE, and 19 percent to 28 percent for SDG&E. Again, the IOUs are currently using an estimate of 15 percent of load. This value does appear to be reasonable among bidders, based on the empirical data presented above, considering the small number of event days, the influence of some large customers over some IOU-specific results, and the weather patterns on and surrounding some of the event days.

Exhibit 7-28 presents the final estimates for the DBP demand reduction, shown as an aggregate MW impact and as a percentage of baseline load across all bidders, as well as a percentage of baseline load across all DBP participants (including those that chose not to bid). Also shown are the median, and the 25th and 75th percentile of the average hourly impacts across all bidders.

For PG&E, the 16.2 MW demand reduction is based on the only DBP event that occurred in the summer of 2004. This event was a test event, which means that it is announced on the morning the event is to occur. Because the PG&E DBP program does not allow for customers to bid on same-day events, it was not possible to pull out the subset of the bidders for this event as was possible for the SCE and SDG&E events. Because of this, the 16.2 MW impact represents a reduction in load of 17 percent for both the bidding and total PG&E DBP participant population, very close to the 15 percent IOU planning assumption. The median impact for this event was 8 percent, with an inter-quartile range of zero to 21 percent.

For SDG&E, the 1 MW demand reduction is based on the most recent DBP event, as this result was nearly identical to the previous event day, and because the first event day occurred in May. The 1 MW impact represents a reduction in load of 28 percent, corroborated by a median impact of 22 percent, and an inter-quartile range of 13 percent to 54 percent. Although these data indicate an impact higher than the 15 percent projection, the 28 percent impact corresponds to only a 4 percent reduction in load across *all* SDG&E DBP participants. This value is so low because only 7 of the 33 (or 21 percent) of the participants chose to bid. The distribution of load reduction expressed as a percentage of load was also developed for all of the participants that did not place a bid. Among all non-bidders, the median impact was zero, with an inter-quartile range of –4 percent to 2 percent. This result helps validate the reliability of the 10-Day Adjusted Baseline methodology.

For SCE, the 9.5 MW demand reduction is based on the second DBP event, and utilizes the 10-Day unadjusted approach for three of the five identified outliers. Because the first event day was found to be biased due to relatively low temperatures on the event day, as discussed above, this event day was not selected. The 9.5 MW impact represents a reduction in load of 12 percent across all bidders, corroborated by a median impact of 11 percent, and an inter-quartile range of 1 percent to 32 percent. However, this 12 percent reduction corresponds to only a 2 percent reduction in load across *all DBP participants*. As with SDG&E, this value is so low because only 24 of the 492 (or 5 percent) of the participants chose to bid. Again, the distribution of load reduction expressed as a percentage of load was also developed for all of the participants that did not place a bid. Among all non-bidders, the median impact was zero, with an inter-quartile range of –4 percent to 4 percent. Again, this result helps validate the reliability of the 10-Day Adjusted Baseline methodology.

Exhibit 7-28
Final DBP Demand Reduction by Utility
Based on 10-Day Adjusted Baseline
MW Load Impact and Distribution of Reduction as Percentage of Load

		Bidders						Participants	
		Average Hourly Reduction and Baseline (MW's)			Distribution of Individual Percent Reduction Impacts			Average Hourly Baseline (MW's) and Reduction	
Utility	DBP Events	Estimated Impact	Estimated Load	Percent Reduction	Median	25th Percentile	75th Percentile	Estimated Load	Percent Reduction
PG&E	#1	16	93	17%	8.1%	0%	21%	93	17%
SDG&E	#3	1.0	3.5	28%	22%	13%	54%	27	4%
SCE	#2	9.5	79	12%	11%	1%	32%	396	2%

8. CPP AND DBP PROCESS EVALUATION

This chapter addresses issues relating to the implementation of the CPP and DBP Programs. First, the goals and scope of the evaluation presented in this chapter are discussed and placed in the context of earlier and ongoing process evaluation work. Next, we describe the current status of the programs; this leads to a discussion of issues that are covered by the process evaluation and the methods that were used to address those issues. Results of data collection efforts are then discussed, both in aggregate and for specific segments (e.g., by size, program, or utility). Finally, conclusions and recommendations are offered.

8.1 EVALUATION GOALS AND SCOPE

The evaluation of the 2004 CPP and DBP programs has been conducted in close to real time since the programs were launched (the programs were launched in the second half of 2003; the evaluation began at the beginning of 2004 and ran concurrent with the programs throughout the year). The initial Phase I Evaluation report presented in March focused on program marketing and assessed the level of awareness among targeted customers. A summary of marketing-related findings in that report is presented in Section 8.2.

A second set of results regarding process issues related to the implementation experience through the early summer and was presented in August to provide feedback to program implementers and to assist the utilities in preparing filings with proposed revisions to the CPP and DBP programs. These results were based on review of program documents and on further interviews with program managers and implementation staff, and are integrated into this report. Aside from providing the basis for the discussions of program status in Section 8.3 and of enrollment procedures in Section 8.5, these results also helped guide further customer data collection efforts by identifying and defining implementation-related issues.

In addition to integrating the findings presented in August, this report provides the results of customer feedback obtained through the participant surveys presented in Chapter 5 -- both post-event and final evaluation surveys. Issues addressed by these surveys and analyzed in this chapter include the following:

- Effectiveness of event notification, tracking, response, and follow-up
- Perceptions regarding the frequency and duration of events
- Perceptions regarding the notification process and the amount of time customers have to respond
- Continued barriers to actual curtailment
- Program satisfaction and likelihood of continued DR program participation

Process-related results of the surveys presented in Chapter 5 are discussed for respondents overall, and then for specific segments as appropriate, including by program, customer size, utility, and business type.

8.2 ANALYSIS OF MARKETING ACTIVITIES AND CUSTOMER AWARENESS

8.2.1 Marketing Activities to Date

One of the key factors influencing the implementation of the DR programs has been the short time frame in which they were developed and introduced. The chronology of events surrounding the programs' approval and implementation therefore takes on additional importance to an evaluation of the progress of the programs to date. A summary of the marketing activities of the IOUs drawn from documents and interviews with program managers at each of the utilities is presented in Exhibit 8-1. While the approach to marketing of the DR programs by the three utilities was similar in many respects, it differed in others, according to the program managers and account reps. Areas of similarity included:

- **Common state-wide collateral**. A decision was made in mid-2003 to develop a single marketing package that would be used by all the utilities, with all the utilities working to develop an agreed-upon format and content and SDG&E spearheading the actual production of materials. The availability of consistent collateral across utilities had the clear benefit of supporting the state-wide approach desired by the CEC/CPUC, but it also made the collateral development process time consuming and more complex. As a result, the statewide collateral package was not available until October 2003. This led both PG&E and SCE to develop their own collateral to support earlier marketing efforts, as discussed below. However, the utility-specific materials were also very similar in their approach and content.

- **A focus on using account managers/executives/representatives as the primary delivery mechanism for the marketing effort.** Most of the market eligible for the DR programs is comprised of customers large enough to have an assigned account representative, and all the utilities used the account representatives as the point of contact for informing these customers about the DR programs. One-on-one meetings were the primary means of communicating, with multiple visits or contacts typically required to complete the marketing and enrollment process.

- **Use of rate analysis to demonstrate the effect of the CPP tariff on the bills of targeted customers.** All of the utilities conducted rate analyses on billing data of all eligible accounts. The rate analyses consisted of hypothetical electricity bills calculated by applying the CPP tariff to the previous year's usage pattern assuming load shifting during CPP events ranging across several scenarios, including a no reduction case. These rate analyses were made available to account executives to use at their discretion during their DR marketing meetings with customers. Account executives were not required to present the rate analyses to all customers and did not believe it was necessary or productive in all cases, particularly for customers for whom rate analyses showed significant increases in bills.

- Focus on AB970 participants. All the utilities were required to focus on AB970 DR participants; however, many of these were direct access customers and therefore not eligible for the DR programs.

Exhibit 8-1

DR Program Marketing Activity Timeline[1]

			Feb.	Mar.	April	May	June	July	August	Sept.	Oct.	Nov.	Dec.	January
	Rate History							SDG&E CPP, DBP Rates filed 7/11, in effect 8/8	PG&E CPP and DBP Rates Approved 8/1/03	SCE CPP and DBP Rates Approved 9/5/03	Statewide collateral available		Revised SCE CPP Rate Approved 12/24/03	
PG&E	**Marketing Activities**		Initial training with 260 AEs			Text-based fact sheet developed		Internal "glossy" collateral developed	Full-scale assigned customer marketing					
						Initial assigned customer contacts			Emeter marketing to unassigned accounts					
	No. of Accts.	DBP								1	5	7	8	8
		CPP									8	14	19	20
SCE	**Marketing Activities**				Product rollout for reps at CTAC				Product rollout for customers at CTAC		Statewide and SCE packets sent out	DBP website training sessions		
				Newsletter				Newsletter	Newsletter		Newsletter		Newsletter	
			DR dicussed in California Electricity Marketplace Updates								Full-scale marketing			
								Internal training for reps						
								Internal collateral developed, used in customer presentations						
	No. of Accts.	DBP								9	39	131	384	393
		CPP												
SDG&E	**Marketing Activities**							Initial one-on-one meetings with customers						
				Internal workshops preparing customers for DR programs										
						Internal collateral done								Full scale marketing kickoff
	No. of Accts.	DBP												5
		CPP												10
		HPO												0

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1 This summary is intended to be representative of activities as summarized by utility representatives and may not include all activities related to marketing DR programs.

Differences in the approach to marketing DR could be seen both in the timing and overall emphasis of the marketing efforts.

- **SCE** had an explicit goal of signing up customers to meet the kW targets set forth in its WG2-related DR goals. The total WG2-related DR goal for the SCE service territory was allocated among account representatives according to their customer base, and the goal was incorporated into each account rep's performance plans. SCE began actively marketing these rates in October 2003, and even before then had sent out newsletters and provided customers with training on the use of its online DBP tool. SCE also internally produced specialized, more in-depth marketing pieces for use in discussions with its customers. SCE used incentives to orient its account representatives to achieve specific signup goals for the DR programs. (Note that SCE had virtually no CPP benefitters in 2003 because of a lag in regulatory approval between a rate reduction for the otherwise applicable tariffs, which occurred in September, and carrying through of that reduction in the CPP December revision.)

- **PG&E** set as its goal to reach 100 percent of eligible customers and make them aware of CPP, DBP, and CPA-DRP programs by the end of 2003. PG&E held an initial meeting with all account managers in February 2003 to provide an overview of the coming rates, but had to wait until late July for final rate approval. Rather than wait for the statewide materials, PG&E developed its own marketing pieces before the statewide materials became available. This collateral was also provided to and used by a contractor hired by PG&E to conduct an email and telemarketing campaign to unassigned accounts. PG&E had reached its goals for 2003 based largely on participation in the CPA-DRP programs. PG&E had goals for its account executives to achieve awareness goals and obtain customer feedback in 2003.

- **SDG&E** chose a later rollout for in-person contacts. SDG&E waited for statewide collateral, but then found that customers were not interested in talking about what they perceived to be summer rates in the fall. Instead, SDG&E held its full-scale kickoff in early 2004 so that it could incorporate end-of-2003 changes to its TOU rate, which is linked to the CPP rate. SDG&E also conducted workshops earlier in 2003 preparing its customers for the CPP, DBP, and HPO programs prior to program availability.

It is clear that the 2003 marketing efforts for all the utilities were affected by the relatively short time frame between the approval of the DR programs and the end of the year. Overall, however, despite the difference in approach, timing, and the extent of utility-specific marketing materials used, the basic message being conveyed to customers was consistent. The statewide collateral helped ensure that representatives from different utilities were "on the same page" when describing the programs to their large time-of-use customers. In addition, as discussed further below, the utilities generally succeeded in achieving significant levels of awareness among eligible customers of the new DR programs.

8.2.2 *Customer Perceptions of Marketing Activities*

Based on the results of in-depth interviews with customers,[2] the overwhelming majority of participants and non-participants learned about the DR programs from their utility representative;[3] only two participants and three non-participants reported learning about the programs from other sources. Many participants said they made their decision to participate based solely on the utility representative's presentation and recommendation.

As the above suggests, the overwhelming majority of participants and most non-participants interviewed hold their utility representative in high regard. Almost all participants and over half of non-participants interviewed said the utility representative's presentation on the DR programs was very effective; only two non-participants (and no participants) rated the presentation as not at all effective.[4]

Responses regarding the quality of collateral and other program materials suggest they are effective. Over 90 percent of in-depth interview respondents said they thought the information was "very effective" or "somewhat effective," although many of these same customers subsequently provided comments that they had not read or did not remember the materials.[5] The few respondents who said the material was "not effective" likewise offered comments that they had not seen or did not remember the materials.

8.2.3 *Account Rep Perceptions of Marketing Activities*

Because of the relative complexity of the DR programs and the difficulty of explaining all aspects of the programs thoroughly in what is essentially a piece of marketing literature, the role of the utility representatives takes on particular importance for these programs. Considerations raised by several program and account managers in connection with their role in marketing the DR programs included the following:

- Several program managers emphasized that their account representatives are not a sales organization; they are more oriented to helping customers make decisions that are in the customer's own best interest.

- In part for the above reason, account representatives say it is very important for them to maintain credibility with the customer. If they are perceived to be promoting programs or actions that have little benefit for the customer, credibility suffers. Some account reps

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[2] In-depth interviews were completed with 28 participants and 34 non-participants.

[3] Results from the quantitative survey indicate that two-thirds of the market learned about the new DR programs from direct contact with their utility.

[4] Results from the quantitative survey indicate that three-fourths of customers recalled receiving some type of information from their utility on the new DR programs; of these, nearly 80 percent said the information received was "very" or "somewhat" helpful.

[5] Sixty-three percent of customers in the quantitative survey reported that they remembered receiving brochures and print materials about the new DR programs.

said that they could not aggressively promote the DR programs to customers who would see only minimal benefits (if any) in return for significant effort and risk.

- A few of the customers targeted by the DR programs had bad experiences with interruptible rates during the energy crisis, and remain skeptical of any program or rate that could cause them to face similar disruptions.

- Account representatives already had a full workload before the DR programs; marketing these programs has been an additional demand on their already busy schedule.

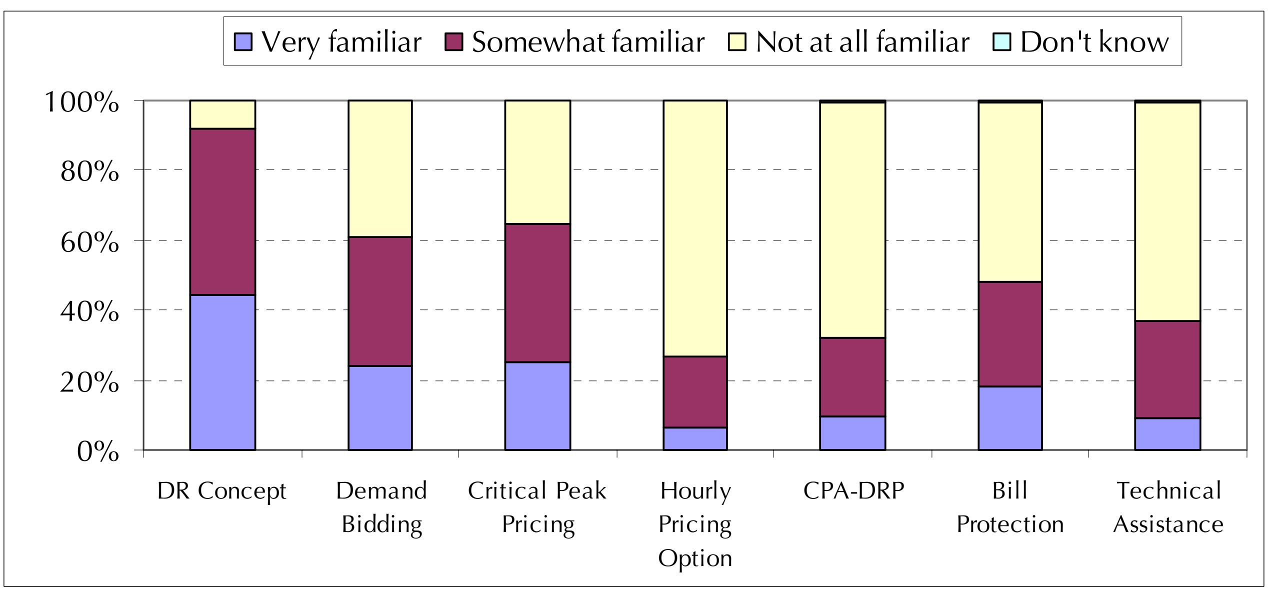
- There is little current sense of urgency among most customers regarding electricity supply and pricing, which makes it more difficult for account representatives to promote the DR programs.

8.2.4 Awareness, Familiarity, and Decision-making Status

Awareness and Familiarity

Customer awareness of the DR programs was assessed through a quantitative survey of 500 non-participants conducted in March 2004. Customer familiarity with the DR concept, four specific DR programs (DBP, CPP, HPO and CPA-DRP), and the incentives being offered to accompany the programs is shown in Exhibit 8-2. The familiarity questions asked about the four programs were all aided questions in which the programs were described with a 1-2 sentence description prior to the customer being asked to state their level of familiarity. The results shown were weighted by energy consumption to more accurately reflect awareness in the overall market.

Exhibit 8-2
DR Concept and Program Familiarity – Quantitative Survey of 500 Non-participants

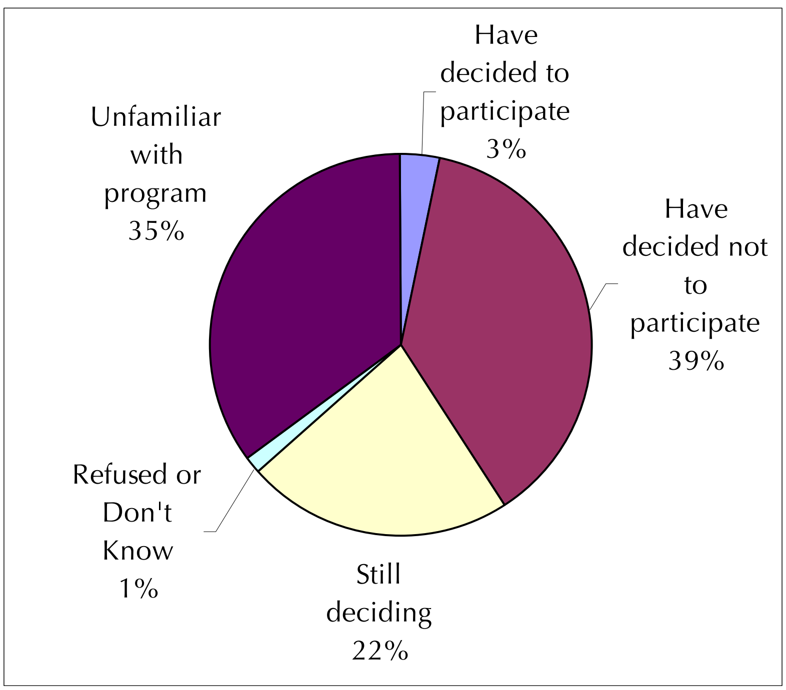


Overall, familiarity with the demand response concept was quite high with 92 percent of the market indicating some level of familiarity and half reporting they were "very familiar". Levels of familiarity reported for the DBP and CPP programs were reasonably high and similar (64 percent versus 61 percent of the market, respectively). Familiarity with the CPA-DRP program was significantly lower, with only one-third of the market reporting some level of familiarity. The main source of information about these programs came from personal contact with their utility.

Status of Decision-making on Program Participation

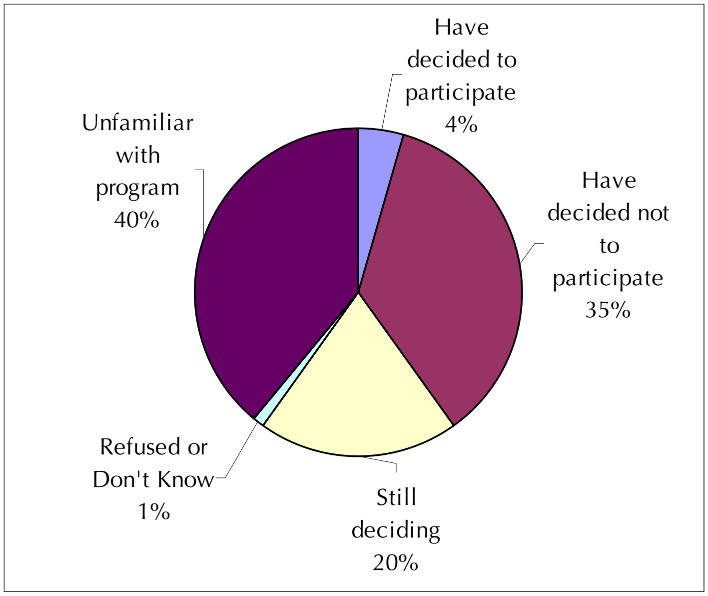
A series of questions asked of all decision-makers familiar with the new demand response programs gauged whether or not organizations had made firm decisions on participation or non-participation in the new DR programs or were likely or unlikely to participate in them in the near future. Responses to these questions were weighted by the decision-makers energy consumption. Results from the quantitative survey are shown in Exhibits 8-3 for CPP and 8-4 for DBP.

Exhibit 8-3
CPP Decision-Making – Quantitative Survey of 500 Non-participants



At the time of the survey more than a third of the market (35 percent) reported being unfamiliar with the Critical Peak Pricing tariff, only 3 percent of non-participants at the time reported they had decided to participate, and 39 percent had made a firm decision not to participate. An additional 22 percent were still deciding or had not yet seriously evaluated tariff.

Exhibit 8-4
DBP Decision-Making – Quantitative Survey of 500 Non-participants



Familiarity with the Demand Bidding Program was slightly lower than that of CPP with 40 percent of the market reporting they were unfamiliar, however the percentage reporting they had decided to participate was very similar to that of CPP (4 percent for DBP versus 3 percent for CPP). Thirty-five percent reported they had made a firm decision not to participate in DBP, 20 percent reported they were still deciding or had not seriously considered participation in the program.

Customers who responded they had not made a firm decision about whether they would participate in any of the three DR programs were asked an additional question to gauge their likelihood of participation (from very likely to very unlikely) based on their current level of information. Combining the results of this question with the responses of those who had made a firm decision regarding participation resulted in an integrated question response that allowed us to estimate the population's overall likelihood of participation[6]. Exhibit 8-5 presents the results of this integrated question showing the overall likelihood of participation in at least one of the three DR programs.

In conclusion, the research conducted earlier in 2004 confirmed that the three utilities had made significant gains in making customers aware of both the concept of demand response in general and the DBP and CPP programs in particular. Subsequent research analyzed both the process by which customers were enrolled and the actual implementation experience, as discussed in the remainder of this chapter.

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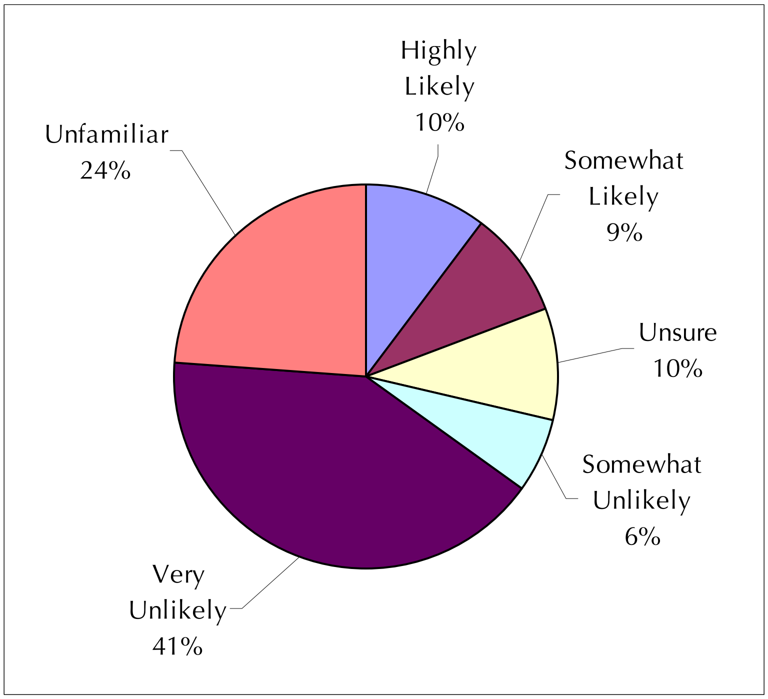
[6] Customers responding they have not seriously evaluated whether to participate were combined with those responding that they were still deciding whether to participate. Customers who responded they didn't think they were eligible were combined with those who responded they have decided not to participate.

Exhibit 8-5
Overall Likelihood of Participation in One of the New DR Programs



Note that 19 percent of the market indicated some level of likelihood that they would participate in one of the programs and 10 percent said they were "highly" likely. The highly likely to participate market was three to four times larger than the current group of participants at the time of the survey; moreover, the percentage of customers reporting they are going to participate in both the DBP and CPP program was much larger than the number of customers that have joined the program since the survey. One would expect self-reports of participation intent would over report actual participation, but there appears to be a much larger gap between self-reported likelihood to participate and current participation than one would expect. Future analysis will be conducted to ascertain whether these customers eventually sign up and, if not, why they changed their decision.

8.3 PROGRAM STATUS

Both the CPP and DBP programs were fielded as state-wide efforts in late 2003, with the goal of having essentially the same programs for all three utilities. Review of program documents and interviews with program staff conducted for the process evaluation revealed differences in several aspects of the programs, as summarized in Exhibit 8-6 and discussed below.

Exhibit 8-6
Comparison of Program Features

IOU	Eligibility	Processing Time	Flow chart or checklist?	DBP Load Reported	Monthly Notification Test?	CPP Events	CPP peak price	Day-of DBP event
PG&E	>200 kW	Anywhere from 2 days to 4 weeks; higher end if meter and phone to be installed and baseline established; CPP can't start until new bill cycle	Yes	Committed Load	Yes	one day ahead	5 times normal on-peak rate	Notifies of system emergency reduction between 12 and 8; customers must reduce by amount of committed reduction (no bids) within 1 hour for up to 4 hours
SCE	>200 kW	From 10-20 business days if meter in place; 4-6 weeks if meter and phone to be installed	Yes	15% of prior year average on-peak demand	No	one day or two days ahead (can cancel two-day on day before)	5 times normal on-peak rate	Notifies by 12, accepts bids until 1, notifies of acceptance by 2
SDG&E	>100 kW	Less than 5 days if meter in place; 2-3 weeks if meter to be installed	No	Committed Load	No	one day ahead	10 times normal on-peak rate	Notifies by 12, accepts bids until 1, notifies of acceptance by 2

Differences among the utility programs included the following:

- PG&E reports a "committed load" for DBP participants, and asks them to reduce the full amount of that load on day-of test events. PG&E tests its notification system (for CPP and DBP as well as other interruptible rates) monthly.

- SCE reports DBP program load as 15 percent of the participant's prior year average on-peak demand. It accepts bids on day-of test events, and can call CPP events either one or two days in advance, with the option to cancel the two-day notice the following day.

- SDG&E has a 100 kW (rather than 200 kW) minimum demand requirement for program participation, accepts bids for day-of events (like SCE), and charges a CPP event price of 10 times the normal on-peak rate (versus 5 times the normal rate for PG&E and SCE.)

- For PG&E CPP customers, savings can occur in summer only; for SCE and SDG&E customers, savings can occur year-round.

The early summer interviews with program staff also identified several issues for further investigation, particularly the low percentage of DBP customers submitting bids in response to test events. In the first round of DBP test events, the percentage of eligible customers submitting bids/load ranged from less than 5 percent to about one-third. Several explanations were offered for this lack of customer response:

- Customer lack of experience with the programs was seen as a likely cause, since many customers who had signed up for the program had not undergone any training in program procedures.

- Another explanation offered was that most of the test events did not take place in the context of external stimuli – such as heat or ISO warnings – that might have alerted customers to the likelihood of an event and reinforced the need for demand reduction.

- Some customers said they never received the notification or were away from the office when the notifications came, so that they did not have enough time to respond.

- In addition, several of the early events identified customer problems with system access, usually because participants had lost their ID or password. While some of these participants retrieved their information from the utility in time to respond, others were unable to do so.

The post-event and final evaluation surveys included questions designed to determine the relative importance of these and other factors in explaining the lack of response to test events, and the implications for the success of the DR programs in 2005 and beyond.

One issue relating to the frequency (or lack thereof) of CPP events is the appropriateness of the temperature triggers that determine how often the program is called. There are indications that the triggers for some regions were set unrealistically high, so that the program would rarely if ever be called. In SDG&E's territory, for example, the CPP program is triggered when the forecast temperature for a certain location reaches 91 degrees; however the forecast temperature for that location has not been as high as 91 degrees in the past five years.

8.4 PROCESS EVALUATION METHODS

As noted previously, the process evaluation of the CPP and DBP programs used data from a variety of sources. The following data sources were used:

- Interviews with program managers and other utility staff, including account managers

- Review of utility filings and program documents

- Post-event surveys with participating customers to address issues of notification, planned and actual customer response, and other concerns

- A final evaluation survey with participating customers to assess their overall perception of program operations for the season.

In the analysis below, both program manager and customer responses are used to present as complete a picture as possible of program implementation.

8.5 PROCESS EVALUATION RESULTS

8.5.1 Program Enrollment and Start-up

Enrollment of new participants in one of the DR programs is a rather complex process that involves numerous departments within the utility affected. The extent to which different groups within the utility have a role in signing up new DBP or CPP customers is illustrated in the flowcharts describing the process for PG&E. Separate flowcharts are shown for initial setup (Exhibit 8-7), readiness review (Exhibit 8-8), and final setup (Exhibit 8-9). Note that PG&E has a separate process for smaller (non-assigned) customers; however all customers are subject to a confirmation that they are on an eligible rate and, as part of the enrollment process, are supposed to take training on the utility's InterAct web tool and to participate in a notification test. In the case of CPP, enrollments cannot be completed until the start of a billing cycle; for DBP, enrollment requires collection of 14 days of baseline data.

SCE's enrollment checklist and the associated enrollment flowchart (Exhibit 8-10) also show the extent to which numerous steps and departments are involved in the sign-up process. For customers themselves, the process is relatively simple, and requires contact only with the account rep. Within the utility, however, a total of 16 separate tasks comprising 75 sub-tasks must be completed before a customer can be enrolled in the program, including several checks to ensure program eligibility.

Interviews with program managers and account staff at all utilities found that these groups generally experienced good communication and cooperation in marketing the DR programs and bringing new customers on board. Both sets of respondents reported a relatively smooth implementation process, although there were continued concerns among both account executives and customers about the complexity of some of the program contracts. For DBP, the contract initially required a separate complete contract for each premise for multi-site customers; this requirement was changed and replaced with a single sheet that covers all a customer's accounts, so that other sites can be added relatively easily.

Despite this streamlining of the contract, delays on customer signing and approval were still said to be more likely because of legal sign-off, failure to sign all documents, missing data than delays in utility processing. Most CPP/DBP customers take from 1-4 weeks to get into the system if a meter is already installed at the participating facility. Issues that can delay or block the process include participation in non-compatible programs, determination that a customer is direct access rather than bundled, and cases where the customer has insufficient load to qualify.

The need to install meters or phone lines creates longer delays. While most new customers currently have the meters and software they need, meter installation may become more of an issue if marketing focuses on smaller accounts. The threshold needed to qualify for the programs has already been reduced slightly by requiring only one month (rather than three) with maximum demand greater than 200 kW, and SDG&E in particular has proposed to reduce the minimum demand required for eligibility substantially. Aggregation of accounts, which is under consideration as an option for the DBP programs, would also be likely to make the enrollment process longer and more complicated.

Exhibit 8-7
PG&E Initial CPP/DBP Customer Setup Flowchart

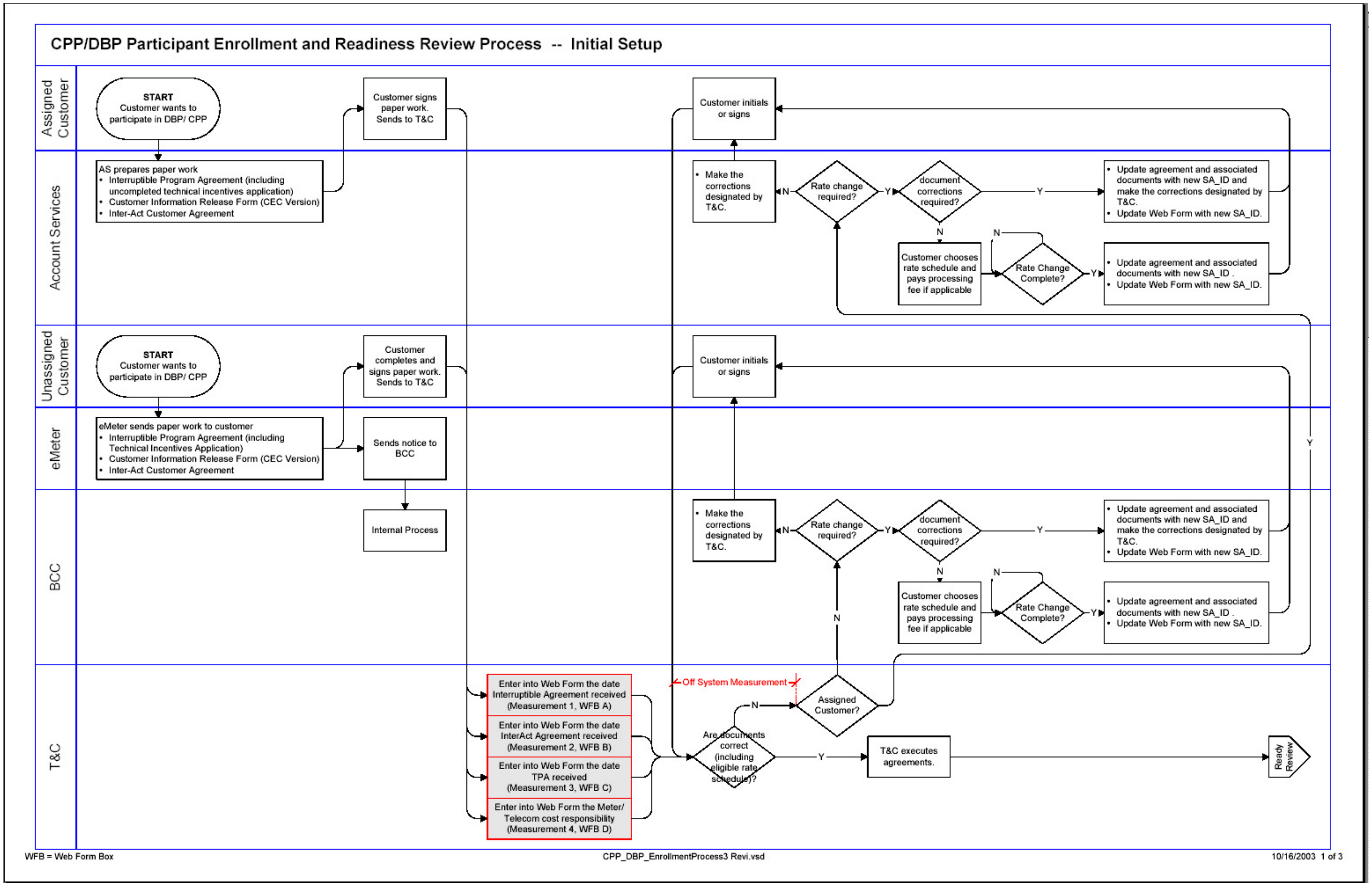


Exhibit 8-8
PG&E CPP/DBP Customer Readiness Review Flowchart

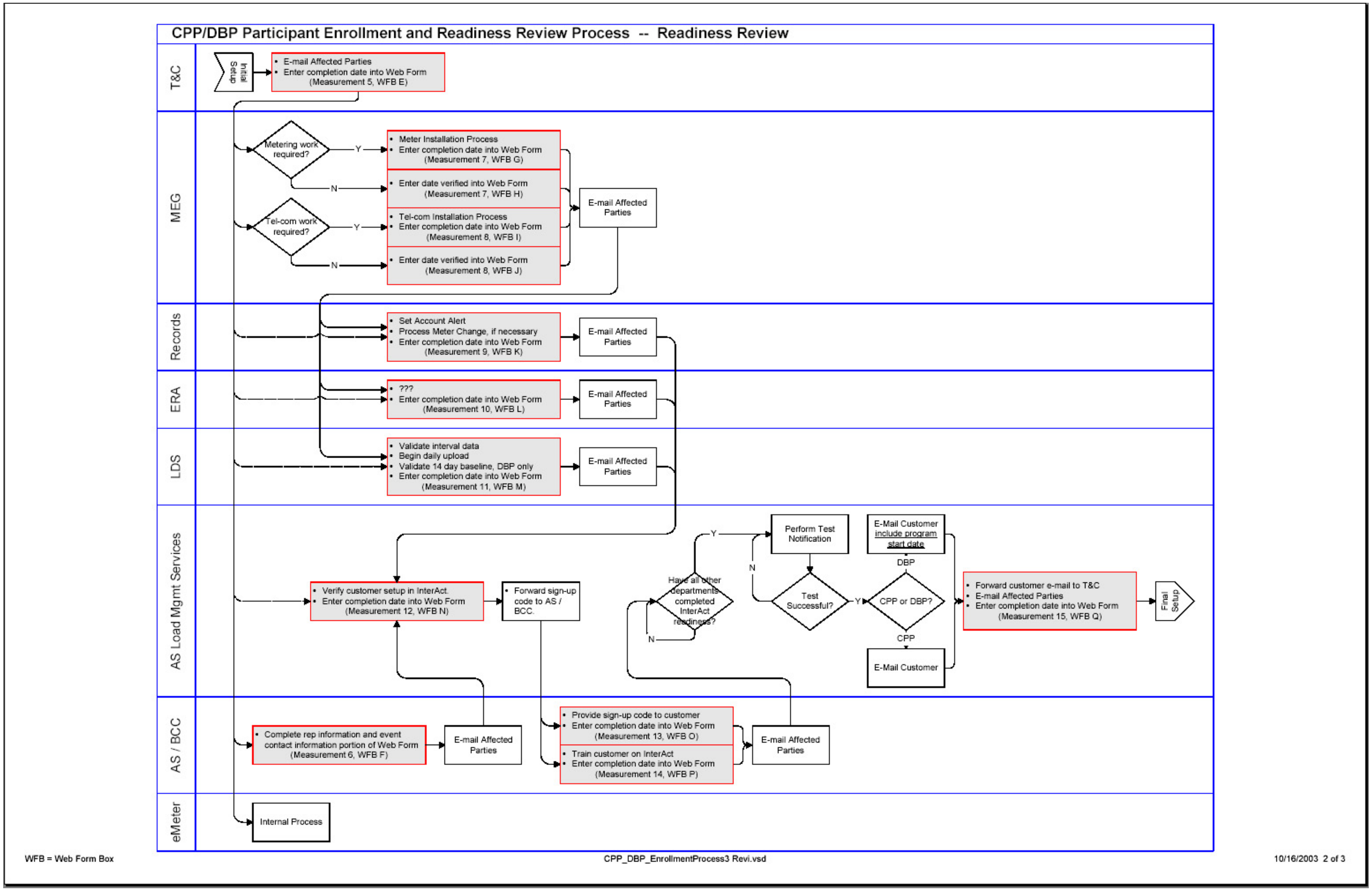


Exhibit 8-9
PG&E Final CPP/DBP Customer Setup Flowchart

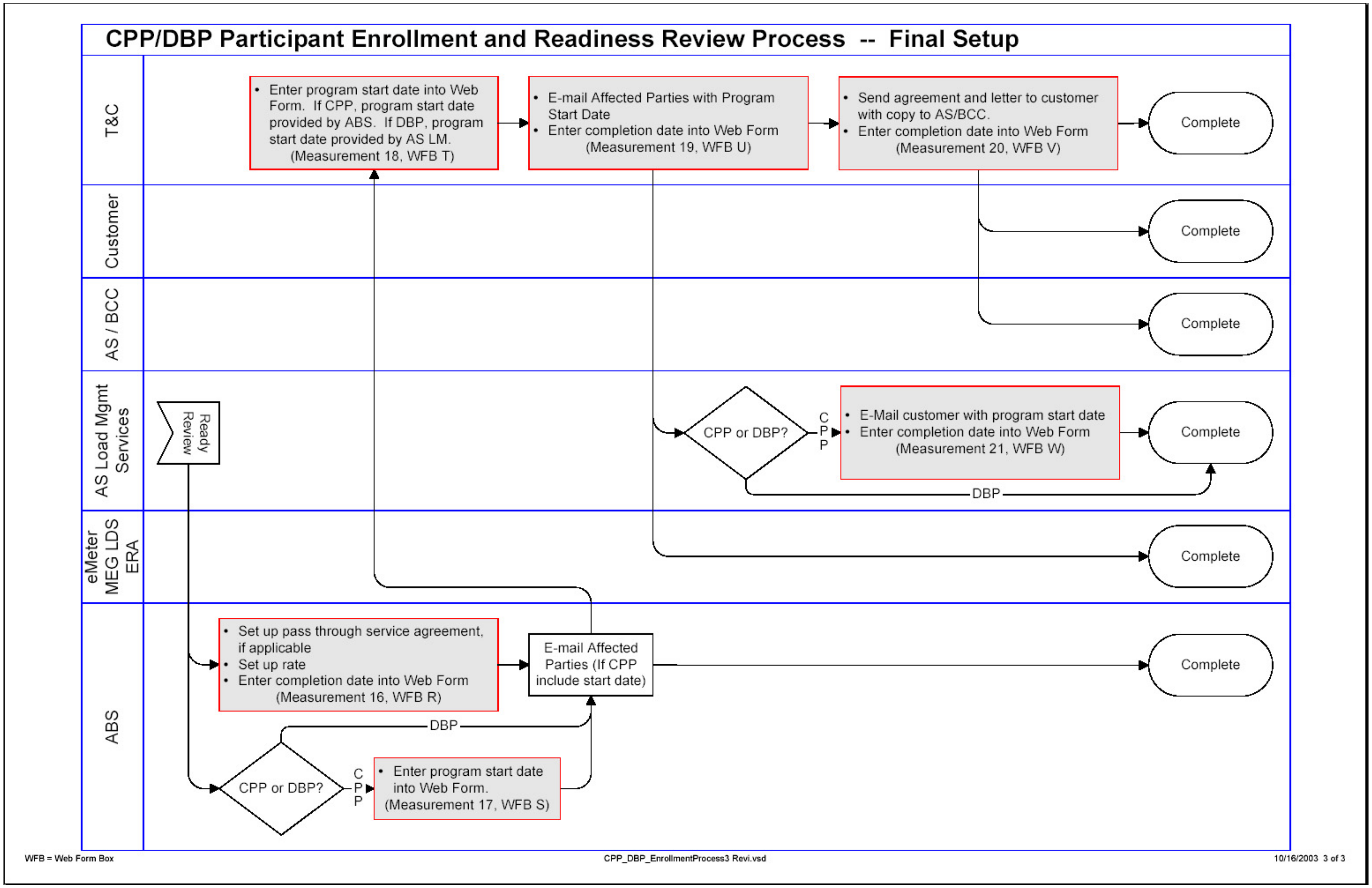
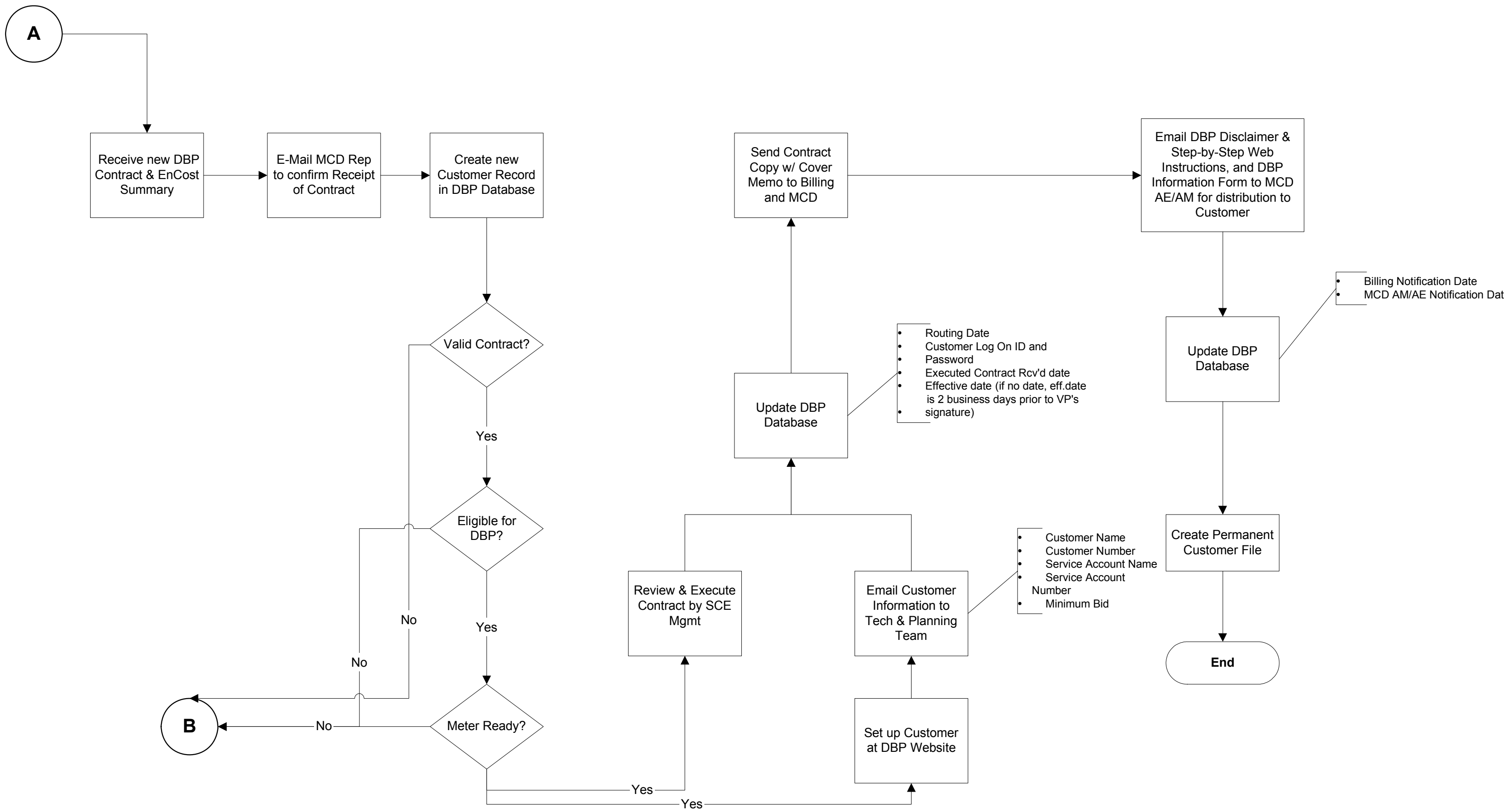


Exhibit 8-10
SCE DBP Enrollment Flowchart



Reporting of DR Program Load

Prior to the summer of 2004, the utilities had no direct experience upon which to base estimates of the load associated with these programs. Estimates of potential impacts have been reported in 2004 to the CPUC using some similar and different methods across utilities and programs. While reporting of curtailable load associated with the DR programs is consistent for the CPP program (all utilities report 15 percent of previous year's average on-peak demand), there have been differences in the way load associated with DBP enrollments is reported.

- SCE reports 15 percent of previous year's average on-peak demand, aggregated across all participants. However, smaller customers would have to bid much more than 15 percent to reach the 100 kW minimum required curtailment, and experience to date suggests that, across all participants, much less than 15 percent will be bid and delivered.

- Both PG&E and SDG&E report committed load – a value agreed to by the customer and the enrolling account executive. As a percentage of customer's non-coincident peak demand, committed load is closer to 60 percent than the 15 percent used by SCE. Moreover, events to date suggest that some of these committed loads may be unrealistic, as discussed in Section 8.5.3 below.

It appears from program manager feedback, as well as from the review of participation in test events this past summer, that the reporting of load associated with the DBP should be revised to more accurately reflect the actual amount of load participating customers are likely to deliver. As discussed in more detail later, there is evidence that the amount of load available for day-of events is significantly less than what would be available for day-ahead events, and the reporting of DR program load should reflect this divergence.

Customer Suitability for Participation

One issue raised during the program staff interviews and confirmed by customer surveys is the extent to which customers have been signed up who really should not be on these programs. As discussed in the March 2004 report, it appears that some account representatives may have encouraged customers to sign up for the DBP program when they were unlikely to be able to curtail the minimum 100 kW required, or for all practical purposes are unwilling to do so. There was some confusion among SCE account reps and smaller customers in particular regarding the 100 kW minimum, with some apparently interpreting the 100 kW as the minimum bid for the program, so that 50 percent of that bid – or 50 kW – would be a sufficient reduction for a customer to be compensated. Any ambiguity in the wording of the program materials was subsequently corrected. Whether it was because of confusion about program requirements or not, a large number of relatively small SCE customers signed up for the DBP program. Most of these customers consequently did not bid on any of the DBP test events implemented by Edison and are still listed as program participants (as noted in Chapter 4, this tends to distort analysis of participant versus non-participant characteristics).

The unsuitability of significant numbers of DBP participants to the requirements of the program is highlighted by the responses to post-event and final evaluation survey questions asking whether customers placed bids, summarized in Exhibit 8-11.

Exhibit 8-11
DBP Bidding

DBP_A. Did you place a bid for the DBP event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	24%	19%	24%	30%	21%	21%	24%	37%	0%	20%	44%
No	72%	77%	74%	66%	74%	74%	75%	59%	0%	77%	53%
Don't know	3%	3%	2%	4%	6%	5%	1%	4%	0%	4%	3%
N*	176	31	58	53	34	76	68	27	0	142	34

* N is the number of customer-events

The results indicate that fewer than 25 percent of all DBP participants surveyed[7] said they placed bids for the DBP events for which they were eligible this past summer; among small customers, the number was only 19 percent. The fact that the percentage placing bids was much higher for SDG&E participants than for SCE participants and the fact that SCE has a large percentage of participants in the small size category (see Chapter 4) suggests that many of the smaller SCE customers alluded to above cannot participate in the program with the 100 kW minimum curtailment. However, our evaluation results have consistently indicated that a large percentage of SCE DBP participants, regardless of size, reported little likelihood of bidding

Responses given by customers who were asked why they did not place a bid also indicate that some participants would have difficulty meeting the requirement of the DBP program. Ten percent of respondents said they were never planning to bid for any event.[8] In addition, 24 percent of participants surveyed said they were very unlikely or somewhat unlikely to place bids for future DBP events as shown in Exhibit 8-12.

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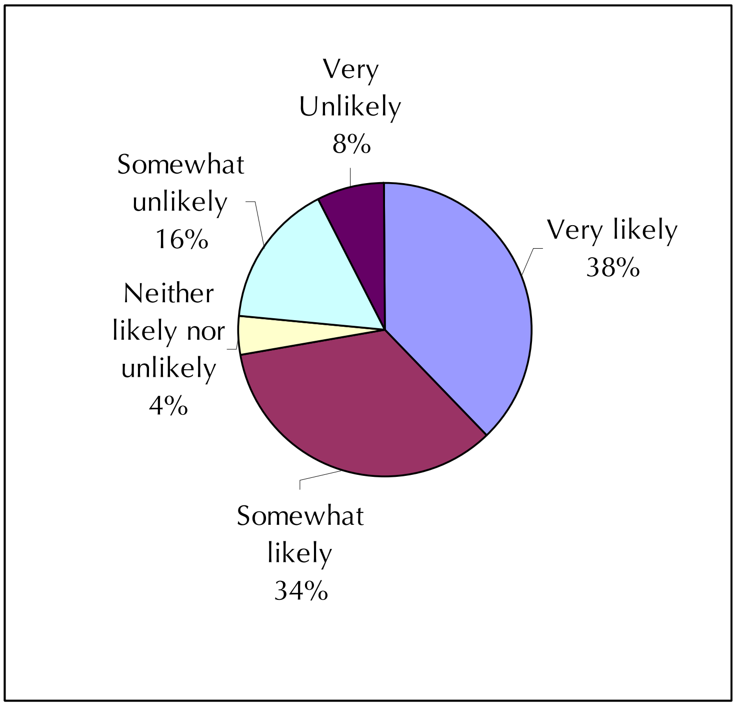
[7] The self-reported percentages reflected in Exhibit 8-11 represent the unweighted responses of only those surveyed. These numbers exceed the actual percentages of customers who placed bids as shown in Chapter 7 of this report, which show that only 25 percent of SDG&E and 5 percent of SCE customers placed bids. The two factors responsible for this overstatement in the actual levels of bidding are the following: 1) the oversampling of SCE DBP bidders due to the large number of SCE DBP participants compared to the relatively small number who bid on the actual DBP events, and 2) customers unlikely to place bids in the program may also be less likely to participate in our evaluation surveys.

[8] Appendix Exhibit E-8 (DBP Reasons for No Bid)

Exhibit 8-12
Likelihood of Bidding on Future DBP Events (All Participants Surveyed)



Breaking down the responses of the participants surveyed by whether or not they reported bidding on any of the DBP events changes the distribution of future program participation significantly. In SCE and SDG&E territories combined (PG&E was excluded since PG&E participants were not allowed to bid for the one DBP event that occurred this past summer), 65 percent of bidders reported that they were very likely to place bids on future DBP events versus only 26 percent of the non-bidders. The percentage of participants surveyed reporting they were very unlikely or somewhat unlikely to place bids for future DBP events was 12 percent for those who had bid in the past versus 33 percent of those who had not previously bid. A complete breakdown of likelihood of bidding on future DBP events by previous bidding history is provided in Exhibit 8-13.

Exhibit 8-13
Likelihood of Bidding on Future DBP Events (Bidders versus Non-Bidders)

	Bidders			Non-Bidders		
What is the likelihood that you will place bids for future DBP events?	Total	SCE	SDG&E	Total	SCE	SDG&E
Very likely	65%	68%	57%	26%	29%	0%
Somewhat likely	23%	16%	43%	37%	38%	20%
Neither likely nor unlikely	0%	0%	0%	4%	5%	0%
Somewhat unlikely	8%	11%	0%	24%	21%	60%
Not at all likely	4%	5%	0%	9%	8%	20%
N	26	19	7	68	63	5

* N is the number of respondents.

Comments from some of these customers emphasize their inability to place bids in the DBP program:

- Because of our customer service, we're not really interested in the program. We signed up for it and we really shouldn't have; we were told it wasn't a big deal to sign up for it.
- We are running a school district. When school is in operation I have no control and I can't shut schools down.
- We're really not a good candidate for the program because we have an ongoing conservation program, so we don't have that much to give.
- We got on the program because we got on back up generators, but it was never convenient to go on the generators and we got rid of the generators a couple weeks ago.
- I shouldn't have signed up for it - there's no really big negative aspect of the program, I just don't think this facility is the right fit for the program.
- We can't shut down a building and its electricity during work hours - we've told [our utility] we can't.
- Because our usage is relatively small, we would never qualify for the minimum bid requirement.

In addition to these comments regarding the participant’s inability to curtail load, several respondents noted that they require advance notification times that are inconsistent with those set forth by the program:

- I need to be able to bid three or four months out in the future to be able to make the difference.
- I need to be notified six months ahead.

- We need a little more of a forewarning - at least two to three days ahead of time so that we can anticipate that something is in the works.

- It's the nature of our business - without more advanced notice we can't make adjustments.

A number of other participants said that they could only participate in the DBP program for events where they have day-ahead notification. Since all the events this past summer were day-of test events, it is not surprising that many customers did not participate. Overall, however, program managers should encourage account executives to screen customers by conducting their own "reality check" based on customer size, business type, and whether the customer has a load reduction plan in mind to respond to DBP events.

For CPP, the issue is less whether customers are right for the program than whether the program is causing any shift in demand. As mentioned in Chapter 1, the CPP program was designed to be revenue neutral meaning that, without any change in their load shape, roughly half of eligible customers would save money by switching to the rate while the other half would see an increase. After they analyzed the effects of the CPP rate on many of their eligible customers, program managers also recognized that some customers would benefit from the CPP rate without making any change to their pattern of electricity usage. The presence of primarily "structural benefitters" in the program is supported by the results presented in Chapter 4, as well as the results of the post-event and final evaluation surveys. Given that the majority of CPP participants appear to be structural benefitters, their self-reported level of load reduction was somewhat encouraging:

- Forty-six unique CPP decision-makers were surveyed about actions they had taken in response to past events. Of the 150 CPP events in question, decision-makers reported taking demand response action for 113 (or 75 percent).[9]

- Among those who had not taken action, 29 percent said they had not done so either because they had already shut down (19 percent) or because did not need to take action to save money (10 percent).[10]

For both programs, the utilities should update their DR program load annually based upon the results of tests and an improved understanding of how much load is realistically available. For DBP, this might mean reporting separate numbers for day-ahead and day-of load, or it might mean reporting a range that reflects the different responses that can be expected under various combinations of prices, day-ahead, and day-of events. Unfortunately, as discussed in Chapter 7, the number, type, and characteristics of events in 2004 do not provide the range of actual results that are needed to robustly forecast future program impacts.

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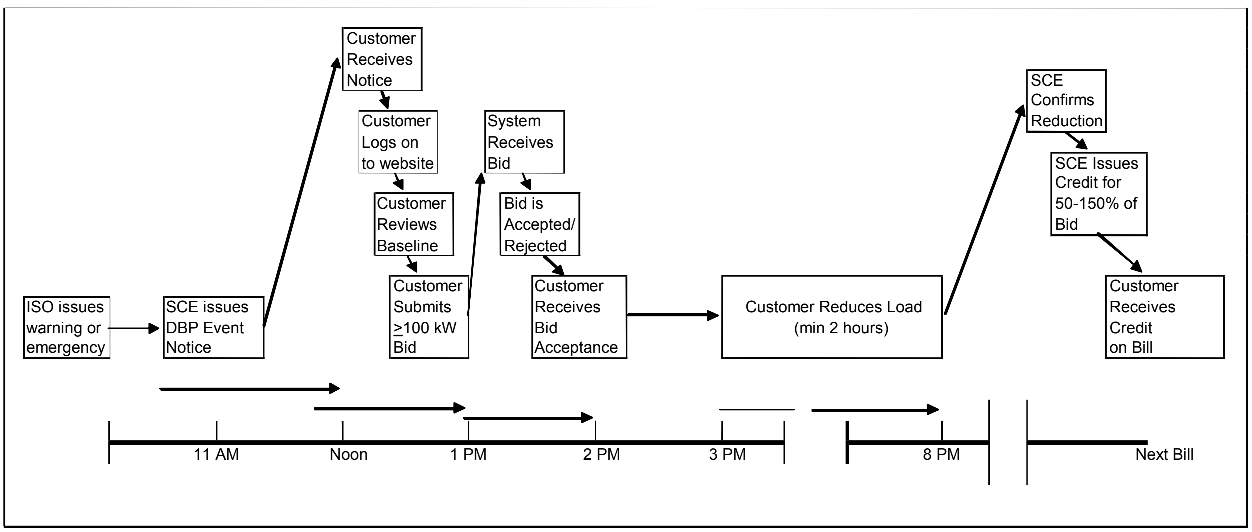
[9] Appendix Exhibit E-1 (CPP Demand Reduction Actions)

[10] Appendix Exhibit E-3 (CPP Reasons for No Action)

8.5.2 *Event Notification*

Because this was the first year of operation for the new/redesigned DR programs, it was important to obtain feedback regarding the effectiveness of the notification process. For DBP in particular, the notification process is critical because participants must respond and place a bid in order to receive credit for a subsequent reduction in usage. To place the notification process in the context of an overall event, Exhibit 8-14 presents the process flow for a day-of DBP event called by SCE. Note that customers must receive the notification, sign on to the SCE website to check their baseline and current usage, and submit a bid for the amount of their load reduction all in as little as one hour. While the bidding process itself is not difficult, it involves several steps, including a review of the customer's current baseline and an assessment of how much to bid so that the actual reduction will be in the 50 percent to 150 percent range required for the customer to be compensated.

Exhibit 8-14
SCE DBP Day-of Event Process Flow



Program manager interviews raised several issues regarding the notification process.

- During the initial DBP test events, both SCE and SDG&E program managers reported some calls from customers regarding notifications that were not received, account log-in problems, or lost passwords. While the problems were resolved for those that called in, this raised the issue of customers not responding because they could not access the website.

- Results of early DBP tests indicated that few customers (anywhere from 5 to 30 percent) were submitting bids.

To investigate the reasons behind this low participation rate, participant post-event and final evaluation surveys included questions addressing both the time frame in which customers are required to bid (for DBP participants) and the amount of notification for a curtailment. In addition, the overall effectiveness of the notification process was assessed as shown in Exhibit 8-15.

Exhibit 8-15
Notification Effectiveness

EV14. In your opinion, how effective was the process by which you were notified of the event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very effective	60%	60%	60%	64%	53%	53%	60%	70%	65%	57%	63%	67%	59%
Somewhat effective	27%	28%	29%	27%	22%	33%	23%	27%	27%	27%	26%	26%	26%
Somewhat ineffective	6%	4%	5%	2%	13%	8%	7%	0%	4%	6%	7%	2%	7%
Very ineffective	4%	8%	2%	4%	3%	2%	5%	3%	0%	6%	4%	4%	3%
Wasn't notified	2%	0%	2%	2%	6%	2%	4%	0%	4%	2%	0%	0%	3%
Don't know	1%	0%	2%	0%	3%	2%	1%	0%	0%	2%	0%	0%	2%
N	161	25	58	45	32	49	75	30	48	86	27	46	122

Overall, nearly 90 percent of participants said they thought the process by which they were notified about events was somewhat or very effective. Regarding variations by segment:

- Ninety-seven percent of institutional participants considered the process somewhat or very effective.
- Extra large customers were least likely to think the process was effective (16 percent thought it was somewhat or very ineffective).
- CPP participants were more likely to offer a somewhat or very effective rating (93 percent) than DBP participants (85 percent).
- PG&E had the lowest percentage (4 percent) of customers who thought the process somewhat or very ineffective, which may reflect the fact that PG&E tests its notification process monthly.

The results of the Notification Effectiveness question for the DBP bidders versus the non-bidders are provided in Exhibit 8-16 (SCE and SDG&E only). This exhibit illustrates that overall, those who had placed bids felt the notification process was more effective than those who had not placed bids (96 percent of the bidders reported it very or somewhat effective versus 82 percent of the non-bidders).

Exhibit 8-16
Notification Effectiveness for DBP Bidders versus Non-Bidders (SCE and SDG&E Only)

	DBP Bidders			DBP Non-Bidders		
EV14. In your opinion, how effective was the process by which you were notified of the event?	Total	SCE	SDG&E	Total	SCE	SDG&E
Very effective	77%	79%	71%	54%	51%	83%
Somewhat effective	19%	16%	29%	28%	30%	0%
Somewhat ineffective	4%	5%	0%	7%	6%	17%
Very ineffective	0%	0%	0%	6%	6%	0%
Wasn't notified	0%	0%	0%	3%	3%	0%
Don't know	0%	0%	0%	3%	3%	0%
N	26	19	7	69	63	6

* N is the number of respondents.

Participants who thought the notification process was not effective generally said this was because they did not have enough time to responds (47 percent), did not read their email (20 percent), or could not respond because they were out of the office (13 percent).[11] The issue of response time is discussed in greater detail below.

Notification Methods

Participants are generally knowledgeable about the type of notification they can expect, and 80 percent of respondents were aware that they could also receive a secondary notification in addition to the one required by the program – also known as a courtesy notification.[12]

Exhibit 8-17
Enrollment in Courtesy Notifications

EV17. Are you currently signed up for any courtesy notifications?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	84%	86%	80%	91%	80%	84%	82%	88%	97%	76%	90%	95%	81%
No	10%	10%	10%	9%	12%	7%	12%	13%	0%	16%	5%	0%	13%
Don't know	6%	5%	10%	0%	8%	9%	7%	0%	3%	8%	5%	5%	6%
N	132	21	50	35	25	44	60	24	37	74	21	37	102

11 Appendix Exhibit E-26 (Reasons for Notice Effectiveness)

12 Appendix Exhibit E-28 (Courtesy Notification Awareness)

As shown in Exhibit 8-17 above, among those who were aware that courtesy notifications are offered, 84 percent had signed up to receive a courtesy notification. By segment:

- Almost all of the PG&E participants (97 percent) said they were receiving courtesy notifications, compared to 76 percent for SCE.

- More CPP customers (95 percent) than DBP customers (81 percent) were receiving courtesy notifications. About 5 percent of both programs' participants did not know if they were receiving courtesy notifications.

Exhibit 8-18 presents participants' preferred method of courtesy notification. Email was the most common (85 percent) courtesy notification; industrial customers were less likely than the general population (79 percent versus 85 percent) to use email and somewhat more likely to use beepers or pagers (29 percent versus 23 percent) – not surprising in that they are more often away from a desk than other decision makers.

In addition to the secondary "courtesy" notifications received by most customers, account executives often placed their own courtesy calls to their customers over the past summer to remind them that an event had been called. SDG&E, for example, explicitly told customers about pending DBP tests to encourage learning from these events.

Exhibit 8-18
Courtesy Notifications Signed Up For

CURTS. Which courtesy notifications are you currently signed up for?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Beeper/pager/text message	23%	17%	21%	28%	25%	14%	29%	24%	51%	7%	16%	26%	21%
Voice mail	7%	11%	10%	3%	5%	11%	8%	0%	9%	4%	16%	14%	6%
Cell phone	16%	17%	15%	19%	15%	11%	19%	24%	23%	14%	11%	23%	13%
Email	85%	94%	85%	81%	85%	89%	79%	90%	83%	86%	89%	91%	83%
Fax	8%	6%	10%	6%	10%	11%	8%	5%	0%	13%	11%	6%	10%
Other	6%	11%	5%	6%	5%	5%	6%	10%	9%	5%	5%	11%	5%
Don't know	1%	0%	0%	3%	0%	3%	0%	0%	0%	2%	0%	0%	1%
N	110	18	39	32	20	37	48	21	35	56	19	35	82

Notification Time - Bidding

While the tariffs and program materials explicitly set out the time frames for notification and curtailment, a number of customers reported concerns both about the time allowed to respond to day-of DBP bid requests and about the notification given for curtailments. Furthermore, the low percentage of program participants submitting bids for test events this summer can be explained in part by the survey responses regarding the amount of time required both to submit bids and curtail load.

As shown in Exhibit 8-19, 50 percent of all DBP participants surveyed said that the one-hour window in which customers can place a bid after being notified of a DBP event makes them less likely to place a bid.

- Large customers were more likely than other size groups to be hampered by the one-hour time frame (63 percent), while institutional participants were less likely than other business types (38 percent).
- Across utilities, SDG&E had the lowest percentage of participants (36 percent) who said the one-hour limit would make them less likely to place a bid.

Exhibit 8-19
Importance of One-Hour Timeframe (All Participants Surveyed)

EV18A. The current DBP notification process allows you up to an hour to place a bid after being notified of a DBP event. Does this timeframe - a maximum of an hour - make it less likely that you will place a bid?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	50%	40%	42%	63%	48%	49%	52%	38%	58%	48%	36%
No	49%	60%	52%	38%	52%	46%	48%	62%	42%	50%	55%
Don't know	2%	0%	6%	0%	0%	5%	0%	0%	0%	2%	9%
N	101	15	31	32	23	37	48	13	24	66	11

Customers who had bid on previous DBP events were 37 percent less likely to report that the one-hour timeframe would make them less likely to bid on future events (33 percent versus 52 percent respectively). A breakdown of the importance of the one-hour timeframe for bidders versus non-bidders is provided in Exhibit 8-20.

Exhibit 8-20
Importance of One-Hour Timeframe (Bidders versus Non-Bidders)

	Bidders			Non-Bidders		
EV18A. The current DBP notification process allows you up to an hour to place a bid after being notified of a DBP event. Does this timeframe - a maximum of an hour - make it less likely that you will place a bid?	Total	SCE	SDG&E	Total	SCE	SDG&E
Yes	33%	38%	20%	52%	52%	50%
No	62%	63%	60%	46%	46%	50%
Don't know	5%	0%	20%	2%	2%	0%
N	21	16	5	56	50	6

In explaining why the one-hour frame made them less likely to place a bid, customers typically said either that they cannot react that quickly (45 percent) or that the person in charge is hard to reach (38 percent), as shown in Exhibit 8-21. Industrial customers were somewhat less likely than others to have a decision maker who is hard to reach (30 percent), but more likely to say that they cannot react that quickly (55 percent).

Exhibit 8-21
Reasons for Importance of One-Hour Timeframe

EV18CM. Why does this timeframe - a maximum of an hour - make it less likely that you will place a bid?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Person in charge of bidding is busy, hard to reach	38%	20%	38%	37%	50%	43%	30%	50%	50%	36%	25%
Takes time to coordinate shutdown within company	15%	0%	25%	11%	25%	21%	10%	25%	0%	14%	50%
Once equipment has started running cannot stop it	3%	0%	13%	0%	0%	0%	5%	0%	0%	4%	0%
Cannot react that quickly	45%	80%	25%	53%	25%	36%	55%	25%	50%	46%	25%
Other	38%	38%	50%	21%	50%	44%	35%	33%	50%	36%	0%
N	40	5	8	19	8	14	20	4	8	28	4

As shown in Exhibit 8-22, when asked how much time they need to submit a bid after being notified, only 32 percent said they need one hour or less or the current time allotted was fine, while another 13 percent said they need 1-2 hours. Eight percent were unsure of how much time they would require, leaving almost 50 percent of program participants requiring not only more time than the 1 hour provided under the program rules, but more than the 2 hours that DBP participants have typically received for test events. (In several test events, the notifications were sent starting at 11 a.m. rather than at noon, so that most customers actually had 2 hours to bid.)

Exhibit 8-22
Time Required to Submit Bid (All Participants Surveyed)

EV18AHM. How much time do you require to submit a bid after you have been notified?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Current is fine	6%	13%	6%	0%	8%	6%	8%	0%	8%	6%	0%
One hour or less	26%	33%	33%	19%	21%	32%	19%	33%	21%	25%	38%
Between 1 and 2 hours	13%	13%	6%	28%	4%	6%	17%	13%	13%	13%	15%
Between 2 and 4 hours	18%	20%	18%	19%	17%	24%	12%	27%	17%	19%	15%
Between 4 and 8 hours	8%	13%	6%	3%	13%	6%	12%	0%	4%	7%	15%
Between 8 and 24 hours	14%	0%	15%	16%	21%	12%	17%	13%	17%	16%	0%
More than 24 hours	4%	0%	3%	6%	4%	3%	4%	7%	4%	4%	0%
Other	2%	0%	0%	3%	4%	3%	2%	0%	0%	1%	8%
Refused	1%	0%	0%	3%	0%	0%	0%	7%	0%	1%	0%
Don't know	8%	7%	12%	3%	8%	9%	10%	0%	17%	4%	8%
N	104	15	33	32	24	34	52	15	24	67	13

As shown in Exhibit 8-23, customers who have placed a bid for a previous event reported needing less time to submit a bid then those DBP participants who had not bid on any events at the time they were surveyed. Sixty-five percent of those who had bid in the past reported that 2 hours or less would be sufficient compared to 39 percent of non-bidders. It was interesting to note that one of the SDG&E participants who had already bid on an event reported not knowing how much time they would require to submit a bid after they had been notified.

Exhibit 8-23
Time Required to Submit Bid (Bidders versus Non-Bidders)

	Bidders			**Non-Bidders**		
EV18AHM. How much time do you require to submit a bid after you have been notified?	Total	SCE	SDG&E	Total	SCE	SDG&E
Current is fine	4%	6%	0%	5%	6%	0%
One hour or less	35%	44%	14%	25%	20%	67%
Between 1 and 2 hours	26%	25%	29%	9%	10%	0%
Between 2 and 4 hours	13%	13%	14%	21%	22%	17%
Between 4 and 8 hours	9%	6%	14%	9%	8%	17%
Between 8 and 24 hours	4%	6%	0%	18%	20%	0%
More than 24 hours	0%	0%	0%	5%	6%	0%
Other	4%	0%	14%	2%	2%	0%
Refused	0%	0%	0%	2%	2%	0%
Don't know	4%	0%	14%	5%	6%	0%
N	23	16	7	57	51	6

Exhibit 8-24 shows that half of the DBP participants surveyed said their bidding requirements for day-ahead events were the same as for day-of events. Others said that bidding for day-of events either required more time or earlier notification (20 percent); that day-of events are "very hard/impossible" for them (12 percent); or that they prefer day-ahead events (9 percent). Only 1 percent said they need less time for day-of events. These results lend further support to the hypothesis that many of the DBP participants are not well suited to the day-of aspects of the program, and help explain why relatively few participants submitted bids for the test events.

Exhibit 8-24
Day-Ahead versus Day-Of Bids

Q18DAY. How is your bidding time requirement different for day-of-events versus day-ahead-events?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
They are not different	50%	53%	52%	41%	61%	49%	48%	62%	33%	56%	55%
Day-of events are very hard/impossible	12%	20%	6%	13%	13%	8%	17%	8%	17%	9%	18%
Less time required for day-of events	1%	0%	0%	3%	0%	0%	2%	0%	4%	0%	0%
Need earlier notification for day-of events	11%	7%	10%	19%	4%	14%	8%	8%	13%	9%	18%
More time is required for day-of events	9%	7%	10%	13%	4%	5%	13%	8%	8%	11%	0%
Prefer day-ahead events	9%	7%	16%	3%	9%	16%	6%	0%	13%	8%	9%
Other	2%	7%	3%	0%	0%	5%	0%	0%	0%	3%	0%
Refused	1%	0%	0%	0%	4%	0%	0%	8%	0%	2%	0%
Don't know	5%	0%	3%	9%	4%	3%	6%	8%	13%	3%	0%
N	101	15	31	32	23	37	48	13	24	66	11

Notification Time - Curtailment

Program participants for both the CPP and DBP programs were also asked about the length of time they were given and the amount of time they needed to reduce their demand. As shown in Exhibit 8-25, 81 percent of customers said they were somewhat or very satisfied with the amount of notification they received, with CPP participants much more likely to be very satisfied than DBP participants. The lower level of satisfaction among DBP participants may be related to their inability to curtail in the time required.

Exhibit 8-25
Satisfaction with Notification (All Participants Surveyed)

ES14B. How satisfied were you with the amount of advanced notification?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very satisfied	36%	30%	56%	27%	17%	22%	34%	54%	51%	27%	38%	62%	28%
Somewhat satisfied	45%	52%	33%	46%	58%	63%	34%	43%	28%	51%	54%	27%	51%
Somewhat dissatisfied	10%	4%	8%	12%	17%	5%	20%	0%	14%	10%	4%	5%	12%
Very dissatisfied	8%	13%	0%	15%	8%	7%	11%	4%	7%	10%	4%	5%	9%
Don't know	1%	0%	2%	0%	0%	2%	0%	0%	0%	1%	0%	0%	1%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

Satisfaction with the notification process was looked into for DBP participants separately to determine if satisfaction with the bidding process could have an impact on whether or not a customer placed a bid for a DBP event. This breakdown, shown in Exhibit 8-26, illustrates that bidders were significantly more satisfied with the notification process than non-bidders (95 percent of bidders were very or somewhat satisfied versus 77 percent for non-bidders.)

Exhibit 8-26
Satisfaction with Notification (Bidders versus Non-Bidders)

	Bidders			Non-Bidders		
ES14B. How satisfied were you with the amount of advanced notification?	Total	SCE	SDG&E	Total	SCE	SDG&E
Very satisfied	30%	35%	17%	23%	24%	17%
Somewhat satisfied	65%	59%	83%	54%	51%	83%
Somewhat dissatisfied	0%	0%	0%	12%	14%	0%
Very dissatisfied	4%	6%	0%	9%	10%	0%
Don't know	0%	0%	0%	2%	2%	0%
N	23	17	6	57	51	6

While DBP participants appear to need less time to actually curtail usage than they do to submit bids (63 percent can curtail within 2 hours, but only 45 percent can bid in that time), a substantial portion cannot meet the requirements of the program, which require customers to curtail on same day events within one hour of having their bid accepted.

It is worth noting that nearly one-fifth of all participants need at least 4 hours – and in some cases more than 24 hours – to be able to respond to a load reduction notice. This highlights the need for account representatives to carefully explain program requirements, for program managers to screen enrolled accounts, and for separate estimation of resource availability for day-of and day-ahead curtailable load.

Exhibit 8-27
Time Needed to Curtail

EV18B. How much time do you need to curtail load in response to the announcement of an event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Current is fine	5%	0%	8%	8%	0%	5%	7%	0%	5%	5%	6%	18%	3%
One hour or less	45%	36%	43%	44%	55%	43%	43%	48%	38%	46%	53%	25%	49%
Between 1 and 2 hours	14%	18%	16%	10%	10%	20%	10%	14%	15%	12%	18%	18%	14%
Between 2 and 4 hours	12%	9%	18%	13%	3%	14%	13%	10%	8%	16%	6%	7%	14%
Between 4 and 8 hours	4%	0%	2%	3%	10%	0%	7%	0%	5%	4%	0%	0%	4%
Between 8 and 24 hours	9%	14%	4%	10%	10%	0%	13%	14%	15%	6%	6%	18%	6%
More than 24 hours	5%	18%	4%	3%	0%	7%	3%	5%	10%	2%	6%	14%	3%
Other	6%	5%	4%	8%	10%	11%	3%	10%	3%	8%	6%	0%	8%
Don't know	1%	0%	0%	3%	0%	0%	1%	0%	0%	1%	0%	0%	1%
N	139	22	49	39	29	44	70	21	39	83	17	28	118

8.5.3 Bidding/Curtailment Process

As shown in Chapter 4 and 7, the percentage of eligible customers submitting bids for DBP events was roughly 25 percent for SDG&E and 5 percent for SCE (PG&E's same-day test did not allow for submission of bids; however, 33 percent of the PG&E DBP survey respondents said they took load reduction action. See Chapter 7 for an evaluation of actual impacts from DR program events.) The lower end of the range may be attributable at least in part to a number of relatively small SCE customers who may have signed up for the DBP under the mistaken impression that they could receive credit by bidding to reduce load by 100 kW and actually reducing load by as little as 50 kW. These customers apparently did not bid during test events. However, as noted previously, our evaluation results have consistently indicated that a large percentage of SCE DBP participants, regardless of size, reported little likelihood of bidding.

In addition, early results showed that customers often overbid or underbid. Only 25 of 42 customers who bid in SCE and SDG&E events received payments, and some may have been paid for much less than they shed, since the program limits payments to curtailments of 50-150 percent of the bid amount.

There has also been some confusion surrounding the PG&E day-of test events. While these are nominally tests of the DBP, PG&E's DBP tariff, as originally written, did not allow PG&E to accept bids for these test events. Instead, customers are issued a notification that says the test event is mandatory and participants must reduce by the amount of their committed load (even though customers face no penalties for failing to reduce). Some customers have confused the notification with that for other interruptible rates of DR programs; others tried to submit bids or contacted PG&E. The level of curtailment for PG&E DBP customers also varied widely, with significant over- and under-bidding. Only 22 of the 31 participants who reduced their usage by more than 100 kW for the first 2004 PG&E DBP test event received any payment, and several provided reductions in excess of 150 percent of their committed load for which they were not compensated (based on the program's 3-Day baseline method, see Chapters 6 and 7 for analysis and discussion of baseline methods and associated impact estimates).

Issues regarding the curtailment process were therefore investigated further using customer surveys. As noted in the previous section, a significant percentage of DBP participants say the minimum amount of notification time required by the program is not enough for them to bid or curtail (although in practice participants have had more time, which may help explain why most were satisfied with the process).

In addition to the timing issue, customers also faced problems regarding how to bid. The extent to which customers were prepared to participate in the program – that is, how to receive and interpret notifications; how to submit bids for DBP; how to curtail load and evaluate performance – varied substantially among respondents.

As indicated in Exhibit 8-28, most participants said they were either very well prepared (38 percent) or somewhat prepared (48 percent) to manage the demand reductions called for by participation in their DR program. However, about 12 percent of DR customers overall said they were not at all prepared, with some commercial customers in particular (16 percent) expressing lack of preparation. These DBP results should be used cautiously though given the low levels of bidding and the fact that more than half of DBP participants said they took no actions at all. Note that CPP participants were less likely to be unprepared, perhaps because they did not need to learn the bidding process.

Exhibit 8-28
How Well Prepared (All Participants Surveyed)

ES8. How well prepared was your organization to manage the demand reductions called for by your utility's Demand Response programs this summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very well prepared	38%	39%	46%	32%	33%	39%	30%	50%	47%	34%	33%	49%	35%
Somewhat prepared	48%	43%	40%	59%	50%	41%	59%	39%	40%	53%	50%	46%	49%
Not at all prepared	12%	9%	15%	7%	17%	17%	8%	11%	12%	11%	13%	5%	13%
Don't know	2%	9%	0%	2%	0%	2%	3%	0%	2%	1%	4%	0%	3%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

Exhibit 8-29 shows the difference in perceived preparedness between DBP participants who bid and those who did not bid. All bidders reported being very well or somewhat prepared to manage their demand reduction actions called for a DBP event versus 81 percent of the non-bidders.

Exhibit 8-29
How Well Prepared (DBP Bidders versus Non-Bidders)

	Bidders			Non-Bidders		
ES8. How well prepared was your organization to manage the demand reductions called for by your utility's Demand Response programs this summer?	Total	SCE	SDG&E	Total	SCE	SDG&E
Very well prepared	52%	65%	17%	23%	24%	17%
Somewhat prepared	48%	35%	83%	58%	59%	50%
Not at all prepared	0%	0%	0%	16%	16%	17%
Don't know	0%	0%	0%	4%	2%	17%
N	23	17	6	57	51	6

Customers who were not at all or only somewhat prepared to manage their demand reduction were asked why they were not more prepared. Results are shown in Exhibit 8-30.

Exhibit 8-30
Reasons for Preparedness

ES8A. Why was your organization only somewhat or not at all prepared to manage the demand reductions?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Have other priorities	27%	33%	35%	22%	18%	20%	24%	43%	18%	28%	33%	26%	26%
Difficult for us to shed much load	22%	33%	19%	22%	18%	16%	24%	29%	23%	20%	27%	21%	21%
Have trouble using the system	18%	8%	27%	15%	18%	32%	10%	21%	18%	17%	20%	16%	18%
Not enough notice	16%	17%	12%	15%	18%	16%	17%	7%	18%	11%	27%	26%	14%
We have a load reduction plan in place	13%	8%	4%	19%	24%	12%	17%	0%	9%	20%	0%	5%	15%
Other	5%	0%	8%	4%	6%	4%	5%	7%	9%	4%	0%	11%	5%
Don't know	1%	0%	0%	4%	0%	0%	2%	0%	5%	0%	0%	0%	2%
N	83	12	26	27	17	25	41	14	22	46	15	19	66

Among customers who were not very well prepared, approximately 18 percent cited "trouble using the system" as the primary reason, while 16 percent said they need more notice. Commercial customers were the most likely to attribute their lack of preparation to trouble using the system. About half of participants said either that they have other priorities than managing demand reductions or that it is difficult for them to shed much load – the latter perhaps representing those participants who should not have enrolled in the program.

When program managers were interviewed earlier this past summer, several noted that they had provided assistance to DBP participants who had lost their user ID or password and were initially unable to sign on when an event was called. Similarly, when responding to a survey question regarding what their utility could do to help them respond to events, a number of DBP participants offered comments regarding their difficulty logging on to the system to submit bids. Sample comments include:

- A little bit more information on how to utilize the website - we don't have any problems reducing our demand, but making the bid is the issue.
- Maybe a walk through or two of how to handle the demand bidding process.
- Maybe another seminar or class - not only on how to bid, but different ways to reduce load/consumption and ideas from other companies that have been successful.
- Some more hands-on training with the system.
- Someone that was more readily available to us to answer our questions when your site was not working for us.
- We need the password for the system - other than that everything is fine - we just need a password.

Thus, while the majority of customers appear to have been adequately trained and supported to participate in the DR programs, extra assistance on how to use the system to submit bids and monitor usage may be needed for some users – particularly those in commercial buildings who may have less technical backgrounds.

Actually reducing load appears to have been less of a hurdle for those who did place bids for DBP events; 95 percent of those participants said they took demand reduction actions (SCE and SDG&E only).[13] In addition, 23 percent of those who did not place bids said they also took demand reduction actions for those events.[14] Furthermore:

- Customers who did not curtail most often said they could not do so "on this particular day." (39 percent of those who did not place a bid gave this as their reason, while 42 percent of those who did not curtail offered this as their reason).[15]

- In response to the question "Is there anything your utility can do to help you bid on future events?" over half of DBP participants simply said "No" and 26 percent asked only for more notice before events. Only one respondent made reference to assistance in understanding their energy usage and actually reducing demand (i.e., "Right now I am working with a consultant that [the utility] brought in - in order to give me options on how to participate.").[16]

- Similarly, 62 percent of CPP participants said there was nothing their utility could do to help them take action in future events, 21 percent called for efforts to raise overall awareness, 8 percent suggested more notification options, and 6 percent asked for longer notification time. None asked for additional assistance in helping them reduce their usage.[17]

- Participants also did not show much interest in technical assistance. Only 1 respondent of 104 offered increased technical assistance as a suggestion for improving the DBP program, and 2 respondents of 37 offered it for the CPP program.[18]

- Participants' perception that they have a good understanding of how to reduce load may explain the relative lack of interest in the technical assistance incentive, while, as shown in Exhibit 8-31, almost half of all participants are not at all familiar with the technical assistance incentive, those who are aware generally do not feel they need it.

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[13] Appendix Exhibit E-10 (DBP Bid and Action)

[14] Appendix Exhibit E-11 (DBP No Bid and Action)

[15] Appendix Exhibit E-8 (DBP Reasons for No Bid); Appendix Exhibit E-13 (DBP Reasons for No Action)

[16] Appendix Exhibit E-17 (DBP Suggestions)

[17] Appendix Exhibit E-5 (CPP Suggestions)

[18] Appendix Exhibit E-84 (DBP Suggestions); Appendix Exhibit E-76 (CPP Suggestions)

Exhibit 8-31
Familiarity with Technical Assistance Incentive

ES11. Are you familiar with the Technical Assistance Incentive available to CPP and DBP program participants?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very familiar	17%	17%	17%	15%	17%	17%	16%	18%	14%	20%	13%	14%	17%
Somewhat familiar	36%	30%	35%	44%	29%	32%	38%	32%	44%	33%	29%	35%	36%
Not at all familiar	47%	52%	48%	41%	50%	51%	44%	50%	40%	47%	58%	49%	47%
Don't know	1%	0%	0%	0%	4%	0%	2%	0%	2%	0%	0%	3%	0%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

Only 53 percent of DBP participants and 49 percent of CPP participants were very or somewhat familiar with the incentives. Of those who were familiar, only 18 participants said they had taken advantage of the technical assistance incentives.[19] In contrast, utility program managers said they were not aware of any customers who had utilized this incentive.

When asked what additional support they would have found helpful in enabling them to reduce their demand, 18 percent of DR participants said they would like specific instructions on how to reduce load; among commercial customers, one-third of participants would like specific instructions, representing over 60 percent of those who wanted this assistance.[20] It seems, therefore, that while most participants believe they have a good understanding of how to respond to DR events, commercial customers in particular may need additional help in identifying opportunities for curtailment.

Participants were also asked about the importance of factors that encouraged or discouraged their participation in the DR programs (using the same questions as we had asked of non-participants earlier in the evaluation, see Chapter 4 for comparison of part/non-part results). Mean importance levels (on a 1 to 5 scale, where 1 is not at all important and 5 is extremely important) attributed to reasons for participation are presented in Exhibit 8-32.

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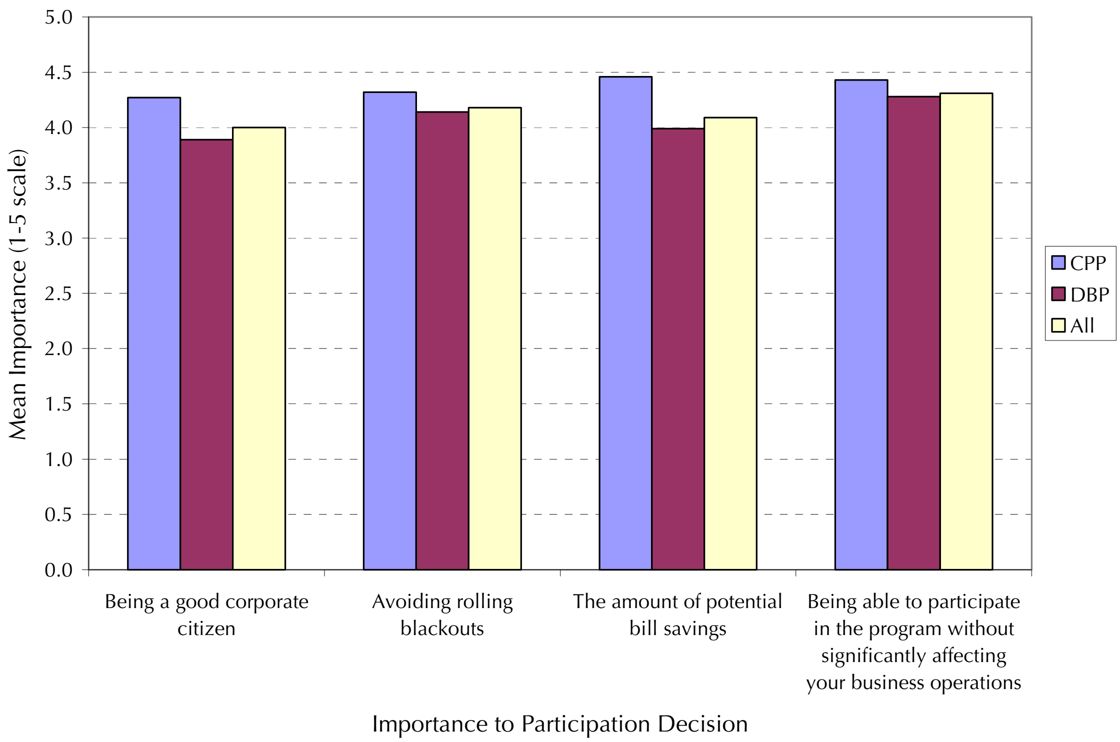
[19] Appendix Exhibit E-52 (Technical Assistance Usage)

[20] Appendix Exhibit E-50 (Additional Support)

Exhibit 8-32
Reasons for Participation in the CPP or DBP



Despite indications from program manager and account executive interviews that many participants signed up to be good corporate citizens, this was seen as a less important reason for participation than avoiding rolling blackouts, saving money, or being able to participate without disrupting business operations. [21]

- DBP customers assigned a lower mean importance to each of the decision criteria than did CPP participants, with the greatest differences for corporate citizenship and bill savings. CPP participants in particular assigned a high degree of importance to potential bill savings and being able to participate without affecting operations – which may reflect the influence of those participants who benefit from the CPP rate without changing their usage patterns.

- Across both programs, large and extra large customers assigned the highest importance to being able to participate without significantly affecting their business operations, with two-thirds of these participants assigning this the highest importance rating.

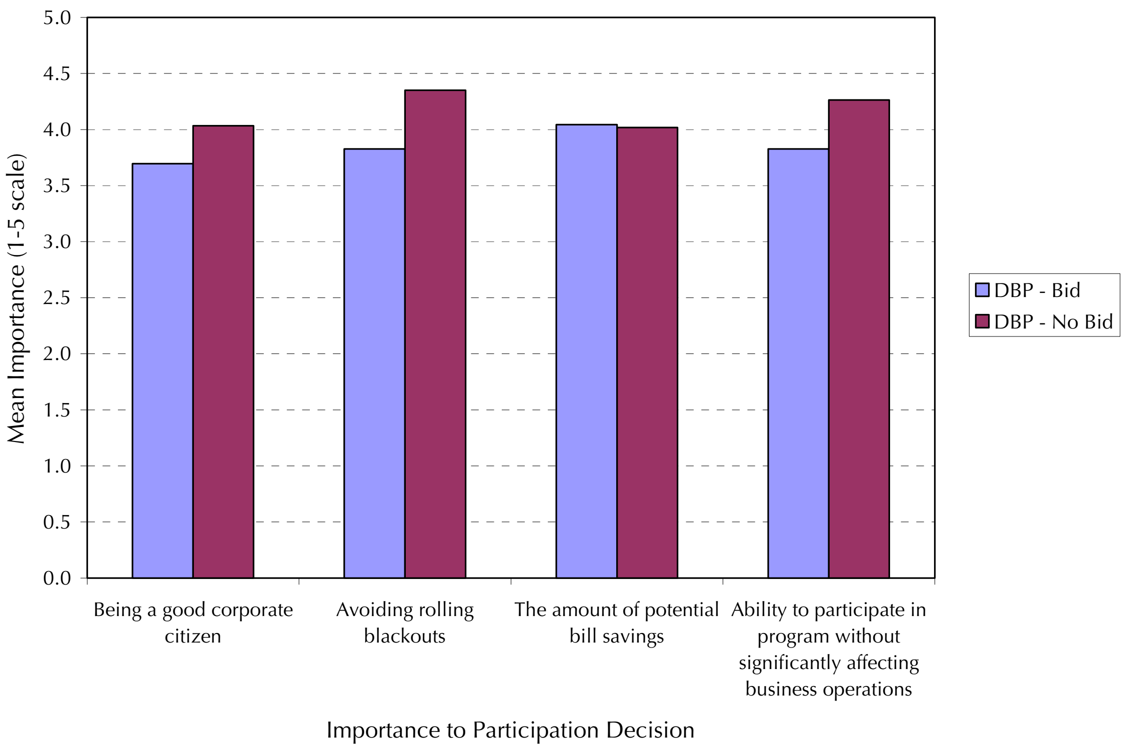
- For commercial customers, avoiding rolling blackouts received the largest percentage of "extremely important" ratings (66 percent), while being able to participate without

[21] Appendix Exhibits E-54 – E-57 (Significance of Various Factors)

affecting business operations received the highest percentage of extremely important ratings for industrial and commercial customers (64 percent each).

Difference in reasons for participation between DPB participants who submitted bids and those who did not submit bids were also investigated, using the same importance scale. Results are presented in Exhibit 8-33.

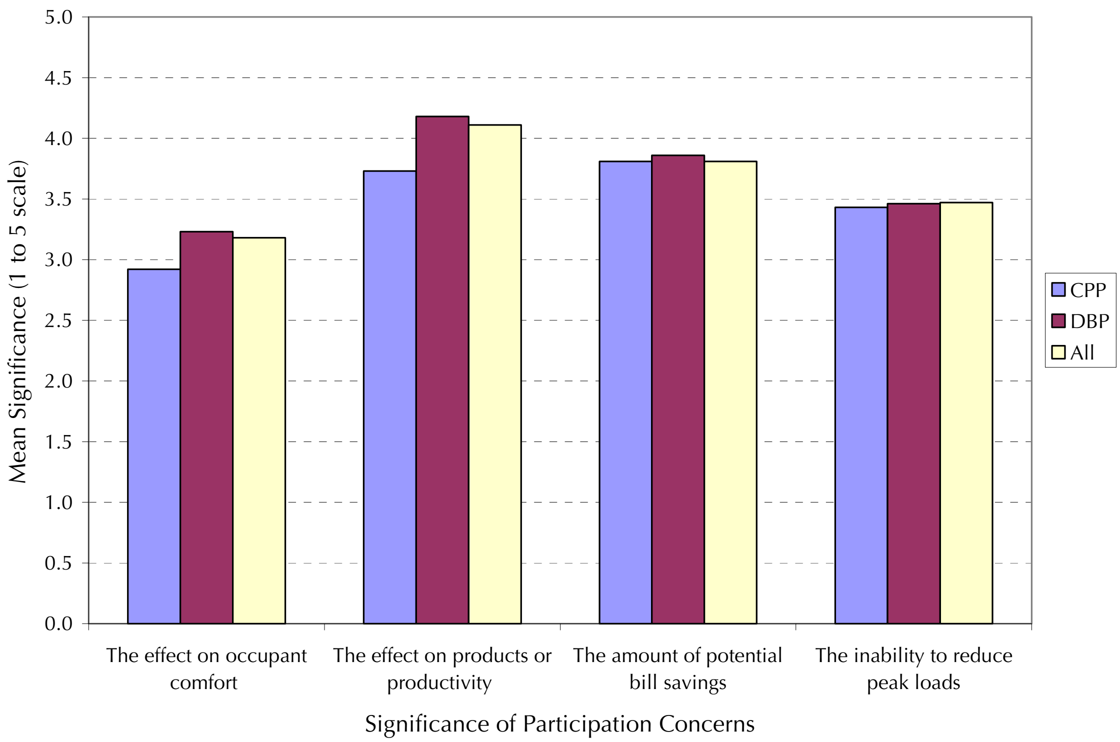
Exhibit 8-33
Reasons for Participation in DBP (Bidders versus Non-Bidders)



As shown in the exhibit, bidders assigned lower mean importance ratings to all reasons for participation except the amount of bill savings, which was the most important reason for participation among the bidding group. Non-bidders, on the other hand, assigned the highest rating to avoiding rolling blackouts. It is possible that these ratings reflect the different perspectives that bidders and non-bidders have on the program; bidders see an opportunity to participate now and earn bill savings; non-bidders do not participate in non-emergency events , but may do so when rolling blackouts are threatened. In the meantime, they do not need to significantly affect their business operations.

Participants were also asked the significance of various barriers to participation, again using a 1 to 5 scale, where 1 means not at all significant and 5 means extremely significant. The mean scores for these barriers are shown in Exhibit 8-34.

Exhibit 8-34
Barriers to Participation in CPP and DBP events



Participants overall generally rated the significance of barriers lower than the importance of reasons for participation.[22]

- Compared to the different importance rankings they assigned to reasons for participation, CPP and DBP participants reported less variation in the relative significance they attributed to various barriers.

- DBP participants were most concerned about the effect of participation on products or productivity, while CPP participants rated (lack of) bill savings as their biggest concern.

With regard to variations by business type:

- Commercial participants expressed the greatest concern about the effect of curtailments on occupant comfort (mean rating of 3.8), while industrial customers had the least concern (mean of 2.7).

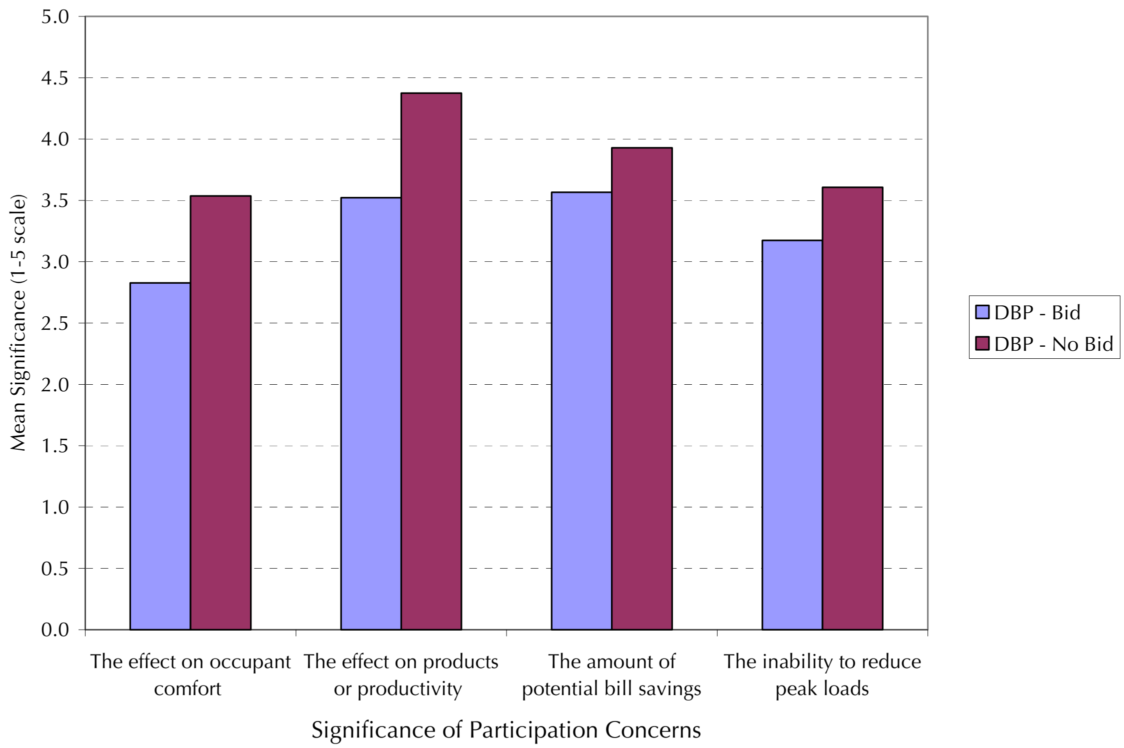
- Institutional customers were least concerned with being able to reduce peak load (mean of 3.2), and were also somewhat less concerned than the other business types about the

22 Appendix Exhibits E-58 – E-61 (Significance of Various Barriers)

effects on products or productivity (mean of 3.9). Industrial customers attached the greatest significance to productivity concerns (mean of 4.2).

Barriers to participation were also compared for DBP bidders and non-bidders. The results are shown in Exhibit 8-35.

Exhibit 8-35
Barriers to Participation in DBP events (Bidders vs Non-Bidders)



Not surprisingly, bidders reported lower averages than non-bidders for all barriers. The difference was most striking for concerns about the effect on products or productivity (3.5 for bidders versus 4.4 for non-bidders). Productivity concerns were the greatest barrier for non-bidders, while bidders saw the amount of bill savings as a somewhat greater barrier than product/productivity effects.

To assess the importance of on-site generation to program participation, customers were also asked whether they have electricity generators on site. Results are shown in Exhibit 8-36.

Exhibit 8-36
Presence of Generators

EV19. Does this site have any on-site electricity generators?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	48%	44%	45%	50%	56%	60%	35%	62%	41%	49%	58%	40%	52%
No	52%	56%	55%	50%	44%	40%	65%	38%	59%	51%	42%	60%	48%
N	156	25	56	42	32	48	74	29	46	84	26	45	117

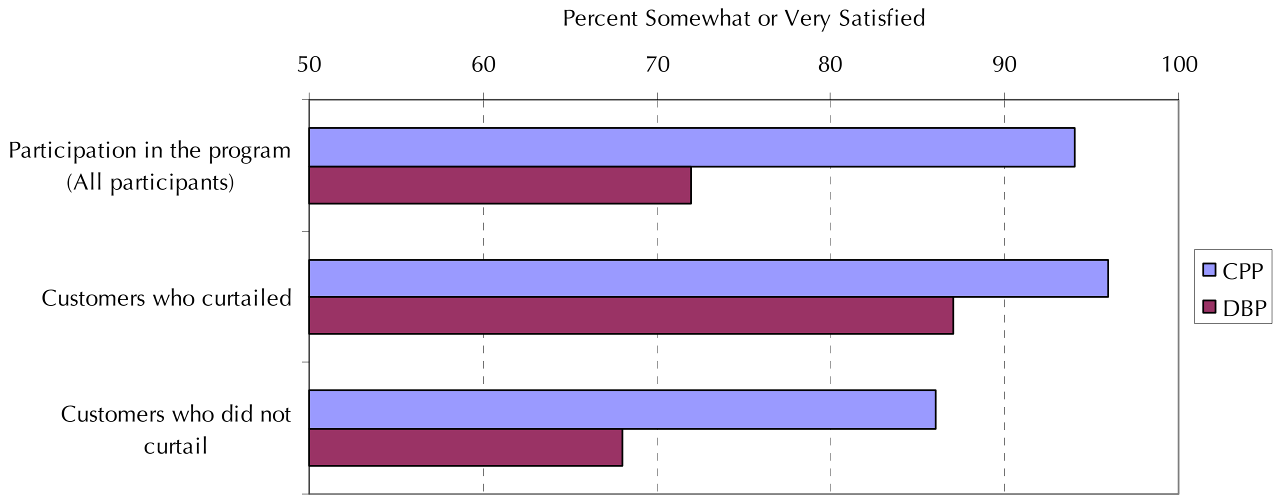
Almost half of participants (48 percent) have electricity generators on-site (62 percent of institutional), but only 12 percent of those who have them say they use them for DBP or another interruptible rate/DR program. Moreover, 56 percent of those who have generators say they face restrictions on how often they can be run during the summer.[23] Among small participants who have generators, only 27 percent say they face restrictions, suggesting that it might be possible to increase the use of these generators for DBP participation, particularly if minimum bid size were to be reduced. However, there may be additional constraints or limitations to the use of these generators than respondents report.

8.5.4 Overall Satisfaction/Intent to Continue

Exhibit 8-37 shows the percentage of participants who were somewhat or very satisfied with their overall participation in the program.

[23] Appendix Exhibit E-38 (Generator Restrictions)

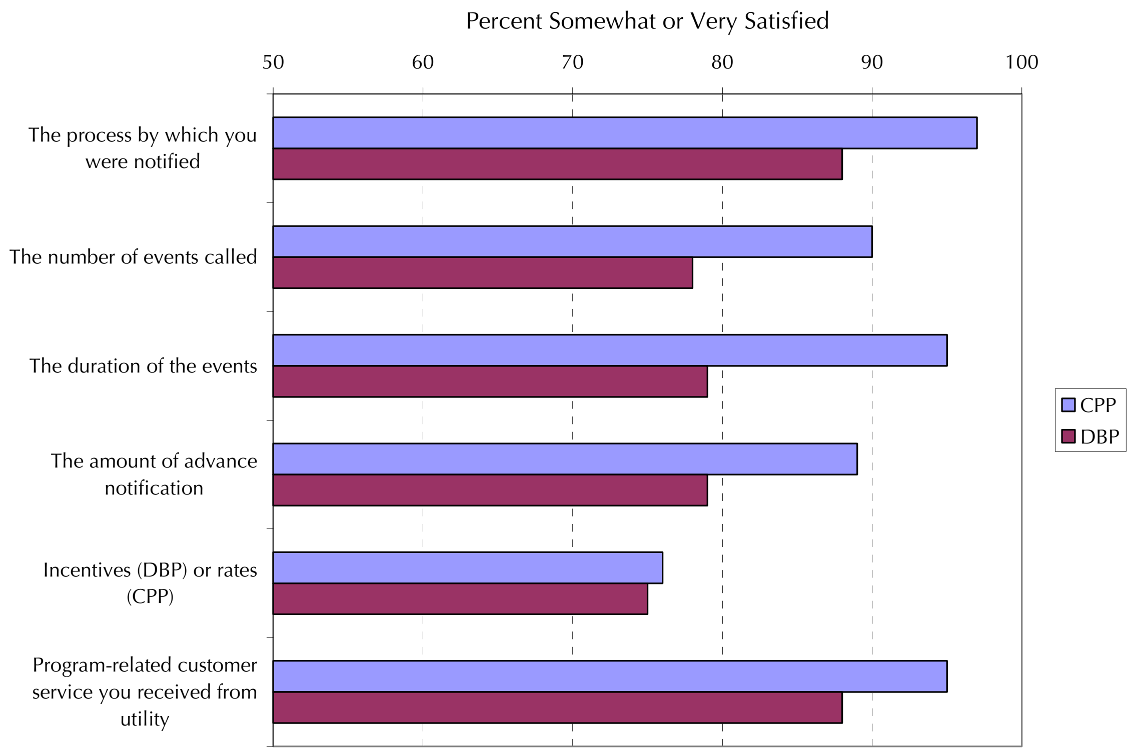
Exhibit 8-37
Participant Satisfaction with their Overall Participation in the CPP or DBP Program



CPP participants generally have higher levels of satisfaction than DBP participants with their program participation overall and with specific aspects of the program (number of events, event duration, notification time.) The difference in overall satisfaction diminishes when only DBP participants who placed bids or took action are considered, reflecting the influence of customers who appear to have been ill-suited to the program.

Exhibit 8-38 shows the percentage of participants who were somewhat or very satisfied with specific aspects of program delivery

Exhibit 8-38
Participant Satisfaction with Specific Aspects of Program Delivery



Note that participants in both programs were least satisfied with the financial aspects of participation and most satisfied with the notification process and the program-related customer service they received. Interestingly, DBP participants were less satisfied with their overall participation than they were with any of the program components they were asked about, indicating that some other aspect of the program may be the cause for their relatively low level of overall satisfaction. Given other comments regarding the bidding process, it may be that participants would have provided lower satisfaction ratings if asked about bidding.

Looking at satisfaction with incentives for DBP participants reveals little difference between the perceptions of bidders and non-bidders (excluding PG&E). Among bidders, 78 percent said they were somewhat or very satisfied with the program incentives, compared to 82 percent for non-bidders.

Several other measures of program satisfaction are provided by customer intentions. First, participants were asked about their intention to participate in future events during the summer. Results are shown in Exhibit 8-39.

Exhibit 8-39
Likelihood of Future DR Actions in CPP and DBP Events

How likely are you to bid (DBP) / take demand reduction actions (CPP) for future events?	CPP All	DBP All	DBP (No PG&E)	DBP - Bid	DBP - No Bid
Very likely	67%	38%	37%	65%	26%
Somewhat likely	17%	34%	33%	23%	37%
Neither likely nor unlikely	4%	4%	3%	0%	4%
Somewhat unlikely	7%	16%	19%	8%	24%
Not at all likely	4%	8%	7%	4%	9%
N	46	119	94	26	68

Consistent with previous findings, CPP participants were much more likely to expect to take demand reduction actions for future events than DBP participants overall. DBP participants who had submitted bids, however, had an even higher percentage of being very or somewhat likely to take action than did CPP participants (88 percent versus 84 percent).

Finally, perhaps the most important measure of program satisfaction is the extent to which participants plan to renew their participation next summer. Participation plans for CPP and DBP participants are provided in Exhibits 8-40 and 8-41.

Exhibit 8-40
Planning to Participate in CPP Next Summer

ES18_CPP. Do you plan to participate in the CPP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	86%	100%	83%	71%	100%	100%	69%	92%	81%	100%	93%
Don't know	14%	0%	17%	29%	0%	0%	31%	8%	19%	0%	7%
N	37	7	18	7	4	7	13	13	21	2	14

Exhibit 8-41
Planning to Participate in DBP Next Summer

ES23_DBP. Do you plan to participate in the DBP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	83%	94%	85%	85%	67%	81%	86%	75%	79%	84%	83%
No	10%	6%	9%	3%	24%	11%	8%	13%	8%	10%	8%
Don't know	8%	0%	6%	12%	10%	8%	6%	13%	13%	6%	8%
N	104	16	33	34	21	36	49	16	24	68	12

Overall, 86 percent of CPP participants and 83 percent of DBP participants plan to participate next year.

- For CPP, Industrial customers were the least likely to know if they would continue their participation next summer (31 percent reported they were not sure).
- For DBP, Institutional customers reported the lowest likelihood of participating next summer (75 percent reported plans to participate compared to 81 percent and 86 percent for Commercial and Industrial, respectively). Twenty-four percent of Extra Large customers (maximum annual demand greater than 2 MW) reported they did not plan to participate in DBP next summer.
- For DBP participants (SCE and SDG&E only), previously bidding on an event this year increased the likelihood of firmly deciding to participate again; among those who placed bids for a DBP event, 91 percent plan to participate again, while only 81 percent of those who did not place bids are planning to participate (9 percent of the non-bidders were still unsure of their future participation).
- Commercial customers who had previously bid were more likely to participate next summer than those who had not bid (88 percent versus 76 percent respectively).

These results highlight the need to either educate/train those DBP participants who have been unable to bid or reduce load, change the testing procedures to enable them to participate, or drop them from the program. However, the results also indicate that at least some of the non-performing participants who should not be in the program will take themselves out.

8.6 PROCESS-RELATED FINDINGS

1. As a result of their DR program participation, 77 percent of surveyed participants said they were somewhat or much more knowledgeable about managing their energy usage at times of peak demand.[24] Moreover, 86 percent of CPP participants and 83 percent of DBP participants plan to participate next year, with the percentage even higher among DBP participants who submitted bids or curtailed their usage in response to events.[25]

2. Based on document review, program manager interviews, and the post-event and end-of summer surveys, a significant proportion of DBP participants probably should not be in the program. Anywhere from 15-30 percent of DBP participants said they never expect to bid, essentially cannot curtail on a day-of basis, or could never curtail enough to meet the 100 kW program minimum. The actual percentage is likely to be much higher since non-bidders are under-represented in our survey results. This has several implications for actions that should be taken by the utilities:

   - Screen new participants to make sure they understand program rules and requirements.

   - Ask new participants and those who have not bid to date to indicate the conditions under which they are likely to bid (e.g., anything from test events to system emergencies) and report the enrolled load accordingly.

   - Provide a clearer explanation of program requirements, including notification times for bidding, curtailing.

   - Provide participants with more training on how to use the program .

3. CPP participants generally have higher levels of satisfaction than DBP participants with their program overall and with specific aspects of the program (number of events, event duration, notification time.) The difference diminishes when only DBP participants who placed bids or took action are considered, reflecting the influence of customers who should not have been enrolled in the program.

4. Not surprisingly, CPP participants include a number of "structural benefitters" who benefits from the CPP rate even without making any change in their usage patterns. While any rate design is likely to provide benefits to at least some customers who do not reduce their demand at all, it would be appropriate for the utilities to periodically re-assess the numbers of both actual and potential structural benefitters under the CPP rate.

5. A substantial number of DBP participants say they cannot respond to day-of events, but indicate that they could participate in day-ahead events. This leads to a recommendation for more and better program testing.

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[24] Appendix Exhibit E-95 (Knowledge)

[25] Appendix Exhibit E-77 (CPP Plan to Participate); Appendix Exhibit E-85 (DBP Plan to Participate)

- PG&E should accept bids for day-of DBP tests so that these reflect actual events.

- Other utilities should test notification systems regularly.

- All the utilities should conduct several day-ahead DBP tests every summer. By using different prices for these tests, program managers could gain a better understanding of how much DR load is actually available under different scenarios.

- Based on the results of these tests, reported DR program load should be updated to be more realistic. This would include reporting separate day-of and day-ahead loads for DBP.

6. Most participants in both programs believe they have a reasonably good understanding of what and how to curtail their usage; commercial customers appear to be an exception, and technical assistance offerings should be targeted to this group.

7. Institutional participants appear to be knowledgeable both about the bidding process and able to reduce their load on short notice, indicating that other customers in this group might be appropriate targets for increased marketing efforts.

8. DBP participants have trouble with receiving and responding to notifications to bid; failure to reach the individual responsible for curtailment by the standard notification process caused some participants to miss opportunities to bid. While most participants already receive some form of courtesy notification, program managers should encourage participants to a) sign up for and use courtesy notifications that will reach key individuals when they are away from their desk, such as alphanumeric pagers or cell phones, b) identify back-up individuals who have authority to place a bid and launch a curtailment, and c) have a bidding strategy and curtailment plan in place that can be implemented even if the primary contact is unavailable.

9. For CPP participants, bill savings are both the most important inducement to participate (of the four investigated) and the most significant barrier to participation (of the four investigated), suggesting that a rate design with greater savings could yield a substantial increase in participation.

9. INTERRUPTIBLE PROGRAMS EVALUATION

This chapter presents the results of a qualitative assessment of reliability-triggered interruptible rate programs offered by PG&E, SCE and SDG&E:

- Traditional non-firm rates ("Non-firm"), including PG&E's Schedule 19 and Schedule 20 non-firm service schedules; SCE's I-6 non-firm schedule and SDG&E's AL TOU CP (including Schedule EECC) service
- Base Interruptible Program (BIP)
- Optional Binding Mandatory Curtailment program (OBMC)
- Scheduled Load Reduction Program (SLRP) and
- Rolling Blackout Reduction Program (RBRP).[1]

The chapter summarizes the scope and issues involved with the evaluation effort, describes the data collection efforts made, briefly describes the programs and presents a comparative program features guide, reviews the curtailment event history of these interruptible programs, and presents the results of program manager and customer interviews (for selected programs) in which experience and insights were obtained to help the assessment.

9.1 INTERRUPTIBLE PROGRAM EVALUATION SCOPE AND ISSUES

The task of evaluating reliability-triggered interruptible programs was assigned a limited scope, as the broader evaluation focused its limited resources more on price-triggered programs. As such, the limited survey activities undertaken of program managers and customers were designed to summarily characterize the programs and compile qualitative feedback on the programs' experience from customers' and program staffs' perspectives. These survey efforts were supplemented by development of a history of the programs' curtailment events, to help understand the programs' history, and a program feature comparison spreadsheet to use in future efforts to further rationalize and integrate the program portfolio.

The activities, objectives, issues and deliverables addressed in this task were:

- Develop an event history to characterize program populations, events and past load reductions. The objective is to help understand the effects of program strengths and weaknesses on participation and impacts. Issues involved include understanding the timing and extent of changes in participation and impacts relative to developments in program designs and operations. The Interruptible Event History is included in Appendix H - Interruptible Event History.

[1] RBRP is offered only by SDG&E.

- Develop a comparative table of program features to help understand the programs' structural and operational differences and commonalities, and thus provide information for future program and portfolio developments. The Program Features Comparison Spreadsheet is provided in Appendix H - Program Features Matrix.

- Conduct and summarize key information from interviews with program managers to identify program strengths and weaknesses, insights and lessons learned, for use in future program developments. [Deliverable: report summarizing key information from program manager interviews]

- Conduct and summarize key information from interviews with a small sample of customers participating in the Base Interruptible Program, the Optional Binding Mandatory Curtailment Program (including the Pilot) and the Traditional Non-firm Interruptible programs. The objective is to identify program issues of concern to customers and obtain feedback on those issues for use in future program developments.

9.2 INTERRUPTIBLE PROGRAMS DATA COLLECTION

Four data collection efforts were undertaken:

1. Compiled data on interruptible program events for the four-year period covering 2000-2003. Standard participation and impact reports from each utility were the source for these data.

2. Compiled data on interruptible program features, utilizing tariff documents and marketing collateral as the primary data sources.

3. Gathered qualitative information from program managers through telephone interviews.

4. Gathered qualitative information from a small sample of participants in the Traditional Interruptible, Optional Binding Mandatory Curtailment and Base Interruptible Programs.

The resulting data were compiled into spreadsheets and interview notes for subsequent analysis and reporting.

9.3 INTERRUPTIBLE PROGRAM DESCRIPTIONS

Five different programs are briefly described in this section, though one "program" really is a program type (Traditional Interruptible) with each of the three utilities implementing its own independently developed variant. The descriptions here are summary only, so the reader is advised to consult the utilities' tariffs for complete details.

Traditional Interruptible Programs

PG&E:

Beginning in the 1980s PG&E offered a "Non-Firm" rate based on its E-19 and E-20 rate schedules. This rate was open to all customers eligible for the E-19 and E-20 rate until 1992, when capacity surpluses led to it being closed to new customers, though existing customers were allowed to continue on the rate through name changes and moves. Beginning in 2004 the rate has been closed even to existing customers if they have changed the account name or moved. Both direct access and bundled customers are enrolled.

The rate provides both rate discounts (in the form of lower demand and energy charges, year-round) and $/kWh penalties applied to excess energy above the contract firm service level. Eligibility is based on a minimum average peak-period demand of 500 kW during the prior six summer months. Customers must have committed to a firm service level of their choosing, including a zero firm service level, but it must have been 500 kW less than the lowest of the customer's average peak-period demands in the prior six-month summer period.

Up to five "pre-emergency" curtailments, each lasting no more than 5 hours, may be called annually. Emergency curtailments may last up to 6 hours, or until PG&E notifies the customer that the period has ended if less than 6 hours, with a 100-hour annual cap. The general conditions for pre-emergency curtailments are based on a mid-morning temperature forecast of above 105 degrees (F) in the Central Valley. Emergency curtailments are called according to Stage 2 and Stage 3 system reliability conditions. A 30-minute notification is provided to customers, communicated via telephone, email or other communications means.

Noncompliance penalties of $0.07/kWh are assessed on excess energy taken during the curtailment period (i.e., demand above the contracted firm service level times the hours during which the excess is taken). A penalty limit applies, however, that restricts the total penalty amount to no more than 200 percent of the annual incentive level.

Customers may decrease their firm service level with 30 days' notice, may increase their firm service level with PG&E's permission during the annual contract review period each November, or may opt out of the program at that time of year. Customers may participate in some, but not all other demand response programs, and there are restrictions in how the customer utilizes other demand response programs relative to the Non-Firm program.

SCE:

SCE began offering Large Power Interruptible service under its I-6 rate schedule in the 1980s, too. The rate continues to be open to "new" loads and "new" customers, but is closed otherwise. Both direct access and bundled customers with new loads or who are new to the SCE service area are eligible.

Customers eligible for the Large General Service TOU-8 rate schedule may take I-6 interruptible service provided they meet the new-load requirements and their stated firm service level will be no less than their maximum demand during the previous 12 months. The customer's firm service level may be zero and must be at least 500 kW less than the maximum peak demand; thus, the customer must have a maximum demand of at least 500 kW. The rate provides both rate discounts (in the form of lower demand and energy charges, year-round) and $/kWh penalties applied to excess energy above the contract firm service level.

Curtailments are called during Stage 2 or Stage 3 system conditions, on 30-minute notice. A remote terminal unit communications system in conjunction with telephone lines is used, and for which there is a fee to cover installation and maintenance costs. Curtailments are limited to 1 event per day, 4 events per calendar week, and 25 events annually. Events are limited to a maximum of 6 hours and total hours of interruption are limited to 40 hours per month or 150 hours per year. Interruptions may be called at any time of day or week throughout the year.

Noncompliance penalties ranging from $7.20-$9.30 per kWh of excess energy (demand above Firm Service level times hours in excess of that demand), depending on the customer's service voltage level. Continuing non-compliance may result in suspension of the discounts applied to the customer's demand and energy billings.

Customers may change their firm service level or opt out of the program during November of each year. There are varying conditions and restrictions in how the customer may utilize other demand response programs relative to the Large Power Interruptible program.

SDG&E:

The "traditional" interruptible rate offered by SDG&E is different than those offered by PG&E and SCE. Where those utilities' traditional non-firm programs have contractually based firm service levels and a discount/penalty scheme applied to demand and energy usage, SDG&E's AL TOU CP rate schedule is actually a time of use program. No firm service levels are specified, nor are there particular discounts or penalties. Instead the rate changes according to system conditions with a 1.80 cent "signal price" that applies to a time-of-use energy charge during critical peak periods (events) defined by Stage 2 or Stage 3 system conditions.

Customers with self-generation are eligible for this rate, with no minimum demand or minimum impact requirements. The customer may operate their self-generation facilities at any time while on the rate. While it is open to both bundled and direct access customers it has no particular benefit to DA customers because its benefits are all contained in the energy charges, and DA customers purchase their energy through other providers. Customers must provide interconnection facilities to enable their self-generation facilities to operate in parallel with the utility's system.

Base Interruptible Program

The Base Interruptible Program (BIP) is a relatively new program developed in 2001 that offers customers demand charge credits for reducing load to a specified firm service level. The program is open to both bundled and direct access customers on large commercial/industrial rates except PG&E, which offers it only to bundled customers. Like the traditional interruptible programs PG&E and SCE have, BIP is based on a firm service level, but it has different impact requirements: committed minimum reductions of either 15 percent of load or 100 kW impact (whichever is higher) are required. Demand charge credits of $7.00 per kW-month of load impact are provided for all load above the firm service level established for the customer (the firm service level being established on the basis of average monthly demand), and significant penalties are imposed on excess energy taken above the firm service level.

Eligibility in BIP is constrained in that if a customer already is on another mandatory-response interruptible program or the OBMC program they are not eligible for BIP. Customers already participating in PG&E's and SCE's traditional interruptible programs, and the CAISO's Demand Reserves Partnership program, may participate in BIP but must first fulfill their obligations under those other programs before being eligible for BIP credits. Customers who participate in BIP may not participate in either the Critical Peak Pricing program or the Scheduled Load Reduction Program. Conversely, restrictions may apply to BIP customers who wish to participate in other demand response programs.

BIP events are called on a 30-minute notice, sent via email and pager and with internet web site confirmation back by the customer, when the utility is notified by the CAISO of Stage 2 or Stage 3 system conditions. Curtailments are limited to one event per day up to 4 hours, 10 events per month and 120 total hours annually.

A noncompliance penalty of $6.00 per kWh is assessed on excess energy used above the firm service level during events. Customers may re-designate their firm service level or discontinue program participation during November of each year.

Optional Binding Mandatory Curtailment Program

The Optional Binding Mandatory Curtailment (OBMC[2]) program is another recent development resulting from the energy crisis of 2000-2001. The program offers blackout avoidance, when the ISO declares rotating outage, in return for up to 15 percent reduction in circuit load during events. The program is unique in its focus on the circuit, or feeder, as the basis for the load being reduced, instead of a building or campus situation within a circuit. Thus, there is a cooperative aspect to the program in that customers who wish to participate in OBMC may need to coordinate load management with other customers on the circuit in order to meet the curtailment requirements.

The program requires that an OBMC curtailment plan be submitted that shows how the circuit loads will be managed in 5 percent increments up to the 15 percent maximum curtailment level. The plan must be updated annually.

To measure impacts the program compares event loads with two differently measured baselines. A 30-minute-based, 10-day previous average is used for determining when 10 percent curtailment levels can be achieved (with certain restrictions detailed in the tariff regarding varying customer operations, unplanned outages, etc.). A facility load-adjusted baseline from the previous year's same month's average peak demand is used for measuring impacts to determine when 15 percent curtailment levels can be achieved.

Curtailments are called for when rotating outages (Stage 3) are required by the CAISO. Customers have 15 minutes to respond before becoming subject to the program's non-compliance provision. There are no limitations on the number or duration of events.

As with other programs, there are certain restrictions that apply to OBMC customers who also wish to participate in other demand response programs, where under certain conditions

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[2] PG&E also fielded a pilot version, POBMC.

participation in other programs is allowed. For example, where the other program requires reduction to a firm service level and the OBMC customer is the only customer on their circuit, that customer may participate in the other DR program. There are additional restrictions that constrain participation in the various other demand response programs as well. Payment of credits from other programs, such as Demand Bidding, is withheld when program events overlap. Also, customers are not guaranteed exclusion from all outages that may include emergencies not included under CAISO rotating outage situations.

A $6.00/kWh penalty is applied to the difference between the event load level and the maximum load level for the circuit. If the circuit load reduction requirements are not met to within 5 percent of the required amount for two occasions in any one year, the customer may be removed from the program and prohibited from participating again for 5 years. Customers may opt out of the program during November of each year.

Scheduled Load Reduction Program

The Scheduled Load Reduction Program (SLRP) is a legislated rate program established in 2001. It offers a credit, and no penalties, for bundled-service-only customers who commit to reduce load by at least 15 percent, with a 100 kW minimum. Customers who participate choose from one to three four-hour periods, during weekdays they select, in which to commit load reductions. The credit offered is $0.10/kWh for reduced energy below the baseline established for each customer. Load shifting to peak periods is prohibited.

The baseline is determined by the rolling average usage of the 10 business days, by hourly time periods, immediately preceding the period during which load reductions are scheduled.

No notice is given in this program, as the customer is expected to routinely schedule their load reductions, with ex-post usage measurements made against the baseline used to determine whether the minimum impact requirement has been met.

While there are no monetary penalties, customers who fail to curtail load as contracted five events in a rolling 12-month period may be removed from the program, in addition to not receiving load reduction credits. Also, the entire load impact must be achieved before any credits are paid (no partial credit allowed).

Customers may discontinue program participation during the November review period each year. SLRP customers may participate in traditional interruptible programs, BIP and DBP during days when SLRP load reductions are not scheduled. SLRP customers may not participate in the CA-DRP, ISO DRP, OBMC/POBMC or CPP programs. They must notify their utility of participation in other programs and may not receive payment for more than one program for load interrupted during a given hour. Obligations for traditional interruptible programs must be met before SLRP impacts may be counted.

Rolling Blackout Reduction Program

The Rolling Blackout Reduction Program (RBRP) is offered only by SDG&E. It offers customers with self-generation an opportunity to reduce the severity of rotating outages called under Stage 3 system conditions. Unlike OBMC it does not exempt participating customers from rotating outages altogether, but instead provides a credit for energy produced by the customer's backup generator during events. Various standby generation requirements must be met for safety and interconnection reasons.

The credit offered is $0.20 per kWh for energy reduced, when the customer achieves their 15 percent demand reduction (100 kW minimum). Credits are paid only for those hours during which the entire obligation is met (no hourly partial credit).

A rolling 10-day baseline is established against which the customer's generator output is measured, with an initial test according to program rules conducted to certify the generator output.

Customers must respond to event notification within 15 minutes. Notification is via email and pager.

Participants are eligible for other demand response programs, but RBRP payments are paid only for generation not on line when RBRP events are called. Customers may discontinue participation upon giving 5 days' written notice.

9.4 INTERRUPTIBLE PROGRAM FEATURES

The program descriptions in the previous section identify a number of structural and operating features. To help evolve the programs in a coordinated manner relative to their various feature sets, a feature comparison guide was developed for this evaluation. Contained fully in Appendix G, the guide contains data on 29 different features:

1. Eligibility: Customer Type
2. Eligibility: Minimum Load Reduction Requirements
3. Other Participation Terms
4. Baseline Criteria
5. Participant Event Action Options & Consequences
6. Impact Performance Measure
7. Other Rate Program Eligibility
8. Incentive Options
9. Payment channel
10. Penalty for Non-compliance
11. Penalty Adjudication/Waiver Process
12. Test Event Actions
13. Event Call Criteria
14. Event Period Definition
15. Maximum # of Hours/Event
16. Maximum # of Events/Week or Day

17. Maximum # of Events, Hours/Month
18. Maximum # of Events/Season
19. Maximum # of Events/Year
20. Notification Advance Time Period
21. Notification Method/Channel
22. Response Confirmation Requirement
23. Tracking Hardware/Software
24. Metering Requirements
25. Meter & Account Aggregation Allowed
26. Technical Assistance Options
27. M&V, Survey Participation Requirement
28. Participation Fees/Customer Actions Required
29. Sign-up & Renewal Periods/Cycles

Comparing the features among the programs and utilities[3] may suggest opportunities to improve consistency and transparency among the programs. Features that vary significantly among programs and/or utilities include the following:

- Customer eligibility, including customer size, type and minimum load impact
- Baseline definitions
- Event period definitions
- Event call criteria
- Notification periods
- Notification method
- Frequency and duration of events
- Impact performance measurement
- Non-compliance penalty levels or structure
- Program fees for metering, communications, etc.
- Tracking hardware/software

There are various reasons regarding why there are differences among the utilities and programs in such features. Most differences are due to program strategies, utility cost structures, ISO system control operations. For other differences there may be opportunities to rationalize the features in order to simplify the overall portfolio and make it easier for customers to understand and participate, as well as for utilities to simplify their administrative processes. No particular

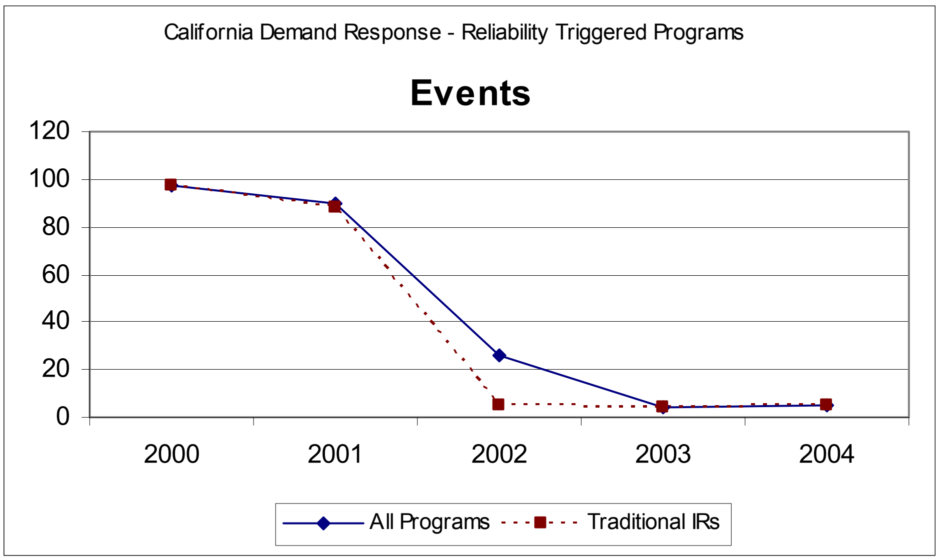
[3] In some cases different utilities implement the same program with somewhat different feature specifications.

recommendations are offered here, however, because undertaking a portfolio feature rationalization assessment is outside this evaluation's scope. Nonetheless, there are indications that such an effort may have value.

9.5 INTERRUPTIBLE PROGRAM PARTICIPATION AND EVENT HISTORY

Since 2000 and through July 2004, there have been 222 events called for these programs. Over 180 events occurred in 2000 and 2001, followed by a radical decline as electricity supply conditions changed. The trend of events is shown in Exhibit 9-1 below.

Exhibit 9-1
Interruptible Program Events 2000-2004



The number of accounts and total MW enrolled in the programs followed suit, but dropouts stabilized in 2001 once the extreme program conditions driven by the supply situation changed. These trends are shown in Exhibits 9-2 and 9-3 (note that 2004 data are though July only, not year-end).

Exhibit 9-2
Interruptible Program Accounts Enrolled 2000-2004

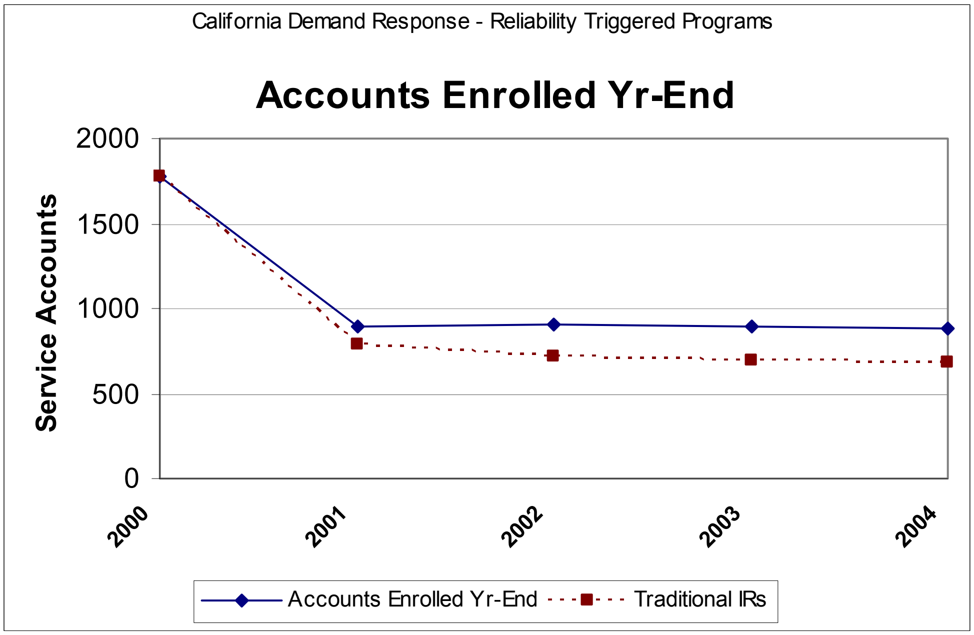
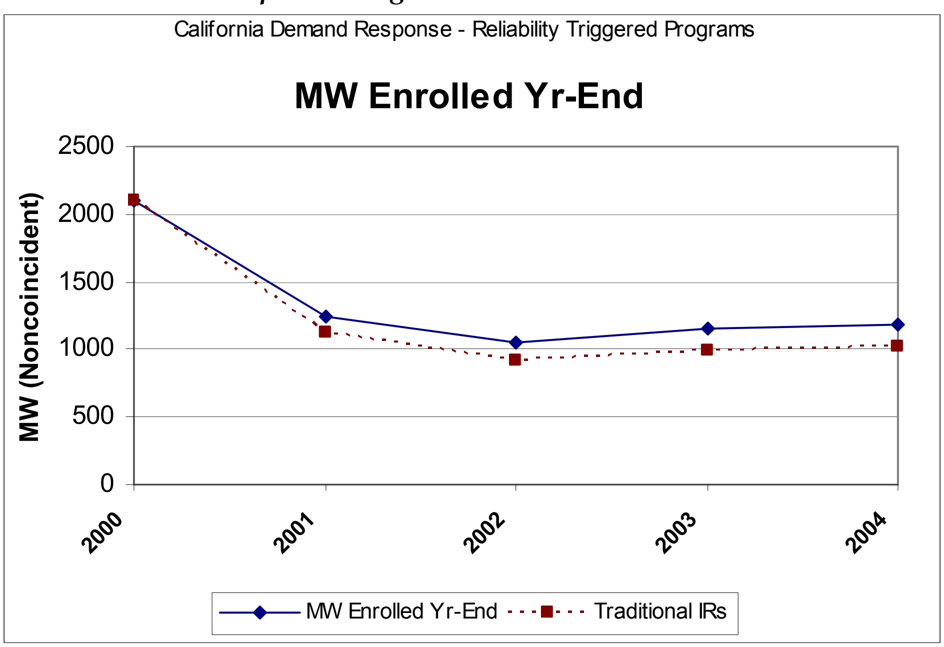


Exhibit 9-3
Interruptible Program MW Enrolled 2000-2004



9.6 INTERRUPTIBLE PROGRAMS INTERVIEW RESULTS

This section summarizes the results of interviews with program managers for all five programs with a small sample of customers being interviewed for only three of the five programs: Traditional Interruptible, Base Interruptible and Optional Binding Mandatory Curtailment. Those three programs were chosen for customer interviews due to the limited evaluation resources available for this effort, and because they were judged as having more outstanding issues of interest. The two programs where customers were not interviewed are geographically limited (RBRP) and either have fewer issues of interest (again, RBRP) or have few customers with the issues relatively well-understood by program staff (SLRP).

The purpose of the interviews was to identify and understand significant program conceptual and process issues of concern to program managers and customers, and to obtain insights on how to address those issues in future program developments.

9.6.1 Program Manager Interviews

The program manager perspective is important because they are both recipients of various forms of feedback from the customers and field account representatives in the field, and also being the interface to upper management and various internal processes supporting the programs. Being functional integrators, program managers view the entire program situation and are called upon to facilitate solutions to everyday marketing, sales and operations challenges. The summary which follows points out both cross-cutting and program-specific issues identified by program managers interviewed at all three utilities, and their thoughts on how to solve problems and build program success. The interviews generally followed an interview guide, though in fact they were relatively wide-ranging and so the results do not lend themselves to a formal tabulation, but rather are reported by program and the following general topics of consideration:

– Strategy

– Relationship to Other Programs

– Technology and Operations

– Administration

These areas include program marketing and customer issues that may be relevant.

Manager Interviews -- Traditional Interruptible (Non-firm) Programs

<u>Strategic Considerations and Lessons from the Energy Crisis</u>

The traditional interruptible programs offered by the utilities long predate the 2000-2001 energy crisis, having been established in the 1980's to address projected peak capacity and energy resource needs at that time. Throughout the 1980s and 1990s the programs had a nominal number of events called that, in general, participating customers considered reasonable in both frequency and duration relative to the discounts and penalties (the discounts, being year-round, were considered relatively generous compared to discounts and credits of more recently developed DR programs).

The situation changed radically when the energy crisis of 2000-2001 occurred, when both the number and duration of events spiked. Allotments of annual curtailment hours were used early in the year, customers grew weary of the constant calls for curtailment, contracted load reductions were not achieved and so significant penalties were assessed. The result, illustrated above in Exhibits 9-2 and 9-3, was that about half the customers enrolled dropped out of the program in 2001 (actually, the trend had already begun in 2000), along with nearly half the load impact that had been built up over the previous 15 or so years. This pattern reflects a wide variation in specific utility program enrollments, however. SCE saw nearly two-thirds of enrolled load and a similar fraction of customer accounts dropping out of the program between year-end 2000 and year-end 2001. PG&E experienced a loss of about 25 percent of load and customer accounts during the same period, while SDG&E actually reported an increase in enrolled load while losing about half the net number of accounts enrolled.[4]

Program managers noted that the instant penalties during the crisis were waived (though those penalties since have been reinstated), which was a reaction to the large numbers of complaints customers registered and to stem additional defections from the program. Caps were also placed on the frequency and duration of events so that customers would not be so severely affected, in hopes again to avoid further loss of participation. These actions are believed to have helped slow the dropout rate.

Ironically, though, the timing of these changes coincided with supply resource developments that alleviated the underlying need to call events. Thus, in the three years since the crisis there have been very few events called and so no real opportunities to test the long-term effect of the event stress-alleviating program changes. Program managers, therefore, remain uncertain about what response levels might be achieved should the supply resource situation again require a significant number and duration of events, that now would be limited by the frequency/duration caps in place. The effect on customers' participation from the significant penalties associated with PG&E's and SCE's traditional interruptible rates also remains relatively untested, although SCE reports having assessed significant penalties for some of the 500+ accounts on the I-6 Interruptible rate, in the two events called in 2004. However, these were isolated and the events did not accumulate or run long.

There is a stalemate of sorts now with these programs, whereby a significant potential demand resource is not being exercised because system reliability is high enough to avoid Stage 2 and 3 conditions that drive these programs' curtailment events. The strategic question program managers are asking is whether there are ways to tap the resource on more of a price basis, to increase the demand resource base triggered by (and to help mitigate) high peak period prices.

SDG&E's AL TOU CP program appears to be one solution to do just this by using a signal price and time-differentiated commodity and delivery component pricing, along with event notification, to achieve its effects – but without the administrative complications of notification confirmation, direct load control operations, measurement of contracted impacts relative to

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[4] This was before the program pricing strategy changed, and is likely due to a shift in the mix of customers in the program.

baselines, etc.[5] Indeed, SDG&E staff indicated that the AL TOU CP program is similar in many ways to the Critical Peak Pricing program, and that customers who had previously dropped out of the AL TOU CP program are being recruited to enroll in the CPP program.

<u>Relationship to of Traditional Non-Firm Programs to Other Programs</u>

How traditional non-firm programs interplay with other reliability- and price-triggered programs is another strategic question, in that there is potential for (at least bundled-service) customers to switch to those other programs. Conversely, utilities may consider altering their program portfolios to migrate customers away from traditional interruptible programs in an effort to tap the resource more frequently through other programs and in hopes of mitigating peak prices. Program managers expressed much uncertainty about whether it would be wise to promote such a change because of the potential for diluting the present resource, noting the lesser performance of demand bidding programs, for example, or seeing lower participation in other programs because those programs' incentives are not as generous. Maintaining this resource as a "deep reserve" in case supply resources once again become scarce (including transmission resources geographically) is seen as a reason to not change the programs' original intent and to retain their basic design, but perhaps with selected design and operational changes to better ensure the resource's long-term availability and impact level.

One observation made was that customers understand reliability-triggered interruptible programs better than price-triggered programs because of the outage consequences reflected in Stage 2 and 3 system conditions. The traditional interruptible programs also have just been around much longer, and so participants have had more time to become familiar with the programs' basic constructs and operations.

Another observation was that reliability-triggered programs seem to not take as long to achieve their impacts when events are called, compared to price-triggered programs. Whether this is due to long-time familiarity as noted above or because of the significance of the penalties involved, or perhaps both together, is uncertain.

Traditional interruptible programs receive less emphasis in the utilities' overall DR program promotion efforts than either the newer reliability-triggered or price-triggered programs, although all marketing collateral includes traditional interruptible programs along with other programs' information. This is probably reasonable since the market is constrained: PG&E has entirely closed their program, SCE restricts its program to new loads and customers and SDG&E targets AL TOU CP only at customers having backup generation (and those tend to be better known and better informed through ongoing utility account management, anyway). As well, utility efforts are necessarily focused on building customer awareness and recruiting customers to the newer programs that are more likely to be utilized.

Other programs' incentives also are generally not as generous as traditional non-firm programs because the other programs' incentives only apply during events, whereas non-firm programs' discounts apply year-round.

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[5] SDG&E had modified its traditional interruptible program in 2002 when the Company's generation assets were sold, which provided the impetus for the change to a primarily price-oriented program.

For SDG&E, the similarity of the AL TOU CP and CPP programs suggests considering how the two programs might be brought together in some way, to simplify the program portfolio and so reduce marketing, administrative and operational costs.

One comment made regarding program interrelationships was about having greater budget flexibility to allow shifting funds among programs to address changing needs over time. Reliability-triggered programs have somewhat greater flexibility in this regard but the thought is that customers' needs are not entirely predictable and change over time, and so program funds should be flexible enough to respond to the situation.

Technology and Operational Considerations

The traditional interruptible programs were begun before advanced metering and communications technologies were widely deployed. As automated metering and more advanced communications technologies have been developed, DR programs have generally embraced them. Thus, newer two-way paging and internet (email and interactive web site) communications systems have been put in place to bolster the traditional, remote terminal unit, fax and manual or auto-dial telephone systems used for event notification and notification receipt confirmation. The older systems remain largely in place, however, because customers like certain features of the old technologies; for example, the remote terminal units still used by SCE remain popular with customers for their simple, highly reliable operation (including providing reliable event notice confirmation back from the customer – a critical issue cited by customers) when properly installed. Remote terminal units are a hassle for the utility to deal with, however, and are not cost-effective compared to new technology alternatives.

Operational communications and administrative testing continues, though no actual load reduction tests are conducted by PG&E and SCE for their traditional non-firm programs (SDG&E does conduct an annual "mandatory day" that comprises a 30-minute actual load test of the AL TOU CP program, however). It is uncertain whether just operational testing is sufficient to assure good certainty of the resource, and there is a trade-off with using up some of the limited frequency and duration of events to gain such assurance. Nevertheless, load reduction testing in addition to process testing may be worth considering as a way to keep customers effectively engaged during years when supply reliability is relatively high. Testing has kept the communications and administrative systems in tune, which has been valuable.

The 30-minute notification periods for the PG&E and SCE programs are believed by program managers to be reasonable and managers report customers have not expressed significant concerns about the period being too short. As is reported below in the summary of the customer interviews, however, some customers find it difficult to meet a 30-minute notification window. Managers did report there are occasional problems that arise from customers being unable to confirm notification receipt and so execute their demand response in a timely manner, which can lead to penalties being assessed and potential requests from customers to waive the penalty assessment. This did not appear to be a fatal concern, but it also was echoed by a couple of the customers interviewed.

Administrative Considerations

Contract processes for traditional non-firm programs are mature and relatively streamlined. This was one strength cited by program managers when comparing the administrative aspects of traditional interruptible programs with newer DR programs.

Depending on the program and the technologies it is using, programmatic (vs. operational) communications such as those concerning program compliance, communications equipment configurations for remote terminal units, or setting meters, may be more involved because of customization issues and the bureaucratic processing of customers' special participation needs.

Annual reviews of firm service levels and other modifications customers are allowed to make in November of each year are similar in many ways to other DR programs, so no significant issues were cited concerning such reviews.

Program managers at SCE and PG&E[6] indicated that establishing and administering firm service levels (baselines) for their programs has not been a major issue, although there are variations among programs on how baselines are defined that may be somewhat confusing to some customers.

Managers Interviews -- Base Interruptible Program (BIP)

BIP Strategic Considerations

Program managers believe the Base Interruptible Program could have good potential as an alternative to traditional non-firm programs, although enrollments have been modest at best so far, leading one program manager to suggest the program may not be worth the effort made to promote it. Another manager lamented about the lack of customers on the program, so customers can appreciate that the benefits of the year-round $7/kW-month on supra-FSL load it provides are indeed reasonably generous. One possible reason is the broader portfolio focus on marketing price-triggered DR programs, to build that strategic set of alternative programs. Another possible reason, noted above per one manager and especially for customers who continue to stay on non-firm programs, is that the incentives for BIP apparently are not viewed as being generous while the penalties are equally onerous.[7] Further, BIP is not available to PG&E's direct access customers, which also constrains that utility's market potential for the program.

One program manager suggested BIP could get greater impacts as well as more accounts enrolled if the minimum customer eligibility level were lowered from 500 kW to 200 kW.

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[6] SDG&E's AL TOU CP has no baseline as such, given that its prices track by time of use and so baselines are inherent in the customer's usage metering.

[7] This point was made by a couple of BIP customers interviewed for this evaluation, as summarized in the next section on customer interview results.

Relationship of BIP to Other Programs

Customers may participate in both BIP and most other DR programs except that PG&E prohibits participation either in SLRP or CPP if the customer is enrolled in BIP. Where a customer is enrolled in BIP and a traditional non-firm program, the non-firm program's curtailment requirements must first be met before BIP eligibility is allowed. Also, concurrent load impacts may not be credited to, or have incentives paid, by multiple programs.

BIP has at least *apparently* lower incentives than traditional non-firm programs, and yet roughly equal (substantial) penalties. This may partially account for the limited enrollments so far, especially among customers still enrolled in traditional non-firm programs and given those programs' precedence rules that require the other programs' curtailment hours to be used before invoking BIP incentives.

As with traditional non-firm programs, BIP is not strongly emphasized in the utilities' DR program marketing mix, because more emphasis is given to promoting price-triggered DR programs.

BIP Technology and Operational Considerations

For SCE BIP has fewer equipment requirements (i.e., no RTU) and so is simpler. Newer communications technology has been employed by all three utilities using two-way paging, email and an interactive web site for event notification. Program managers consider such technologies significant improvements, though they appear to have been layered on top of previous technologies and operational means (such as personal telephone calls and RTUs), so this aspect of BIP (and other DR programs) is not necessarily simpler but is more robust.

Process testing has been done regularly for this program, and program managers reported no significant issues there. Experience with the 30-minute notification window is lacking because of the dearth of BIP events, though testing indicates a very high (~95 percent) notification compliance rate.

BIP Administrative Considerations

BIP is reported to have fewer compliance issues than traditional non-firm programs (SCE in particular noted this), and has a simple contract like non-firm programs tend to have. Program managers did not cite other administrative issues as being significant.

Manager Interviews -- Optional Binding Mandatory Curtailment (OBMC) Program

OMBC Strategic Considerations

Conceptually, the OBMC program appears sound in that reducing feeder circuit loads is of major interest in DR program impacts. The program presents significant challenges in practice, however, due to the requirement that the entire circuit load be reduced, even though (where multiple customers are on the circuit) there may be only limited interest among customers on that circuit to participate in the program. This forces those customers having program interest to take a lead role in working with other customers to ensure sufficient impacts are achieved to meet the program load reduction requirements. In effect, therefore, this program has the greatest appeal to very large customers having dedicated feeders serving them and so no other customers with whom events and load reductions must be coordinated.

As with BIP and traditional non-firm interruptible programs, the $6.00 per kWh noncompliance penalty level for OBMC is substantial and perhaps too onerous even though customers receive the program benefit of being exempted from rotating outages called by the CAISO.

Relationship of OMBC to Other Programs

OBMC has program coordination rules like other programs, so that incentives are not paid for overlapping load impacts. Program managers did not cite significant issues with the program's relationship to other DR programs. It was noted, however, that account representatives may be less knowledgeable about OBMC than other programs.

OMBC Technology and Operational Considerations

Operationally, the lack of events has prevented a full test of the program processes, so program managers are uncertain about what issues may be latent. For example, the 15-minute notification window is extremely tight and may present a problem to customers such that the program is less attractive to them. Technologically, customers must respond to events very quickly, so event communications systems need to be very robust and customers must have the wherewithal to respond almost instantaneously.

OMBC Administrative Considerations

The program has a relatively complex method, compared to other DR programs utilizing some form of baseline, for determining the Maximum Load Level (MLL) against which the circuit impacts are measured. One program manager identified a customer case where the SCADA data for making the MLL determination and the associated impacts had to be manually processed to estimate the impacts, which is very laborious and inefficient, taking more time to process than all the other participants' determinations combined.

Contracts for OBMC were cited as being somewhat more complicated than other programs such as BIP and non-firm programs, and again the few customers in the program may not reflect the full play of potential issues concerning contracts being drawn up or changed over time. One program manager suggested that their administrative process for changing OBMC contracts (even a simple name change) requires nearly full reprocessing of the agreement through various internal departments.

Managers Interviews -- Scheduled Load Reduction Program (SLRP)

SLRP Strategic Considerations

Program managers all agreed this program, though conceptually simple,[8] is strategically out of synch with the intent of demand response programs. That is because the SLRP option menu structure allows (indeed, locks in) load reductions during times when they often are not needed from a system reliability perspective, or even a price perspective. Further, customers receive the same 10-cent per kWh credit regardless of when they deliver impacts, so the price signal to customers is misaligned as well. Customers apparently agree, as only 16 accounts are enrolled in the program across the three utilities, all but one being in SCE's service area. One issue is that scheduling loads as large as the 100 kW minimum required for the program can be difficult, whereas smaller loads, represented by such end uses as lighting and HVAC equipment, may be more amenable to such a program – but they are ineligible unless the customer is able to coordinate their aggregate impact. One manager opined that customers would be better off participating in the DBP program instead.

Customers also may be better off considering energy efficiency measures that can deliver impact year-round and thus avoid the hassle of scheduling and managing load reductions on a routine basis all summer long (the program prohibits load shifting into peak periods, but allows it the other direction). Good energy management systems probably can better address customer billing demand and energy savings opportunities without the hassle of SLRP's other program requirements and associated modest incentives. Indeed, such systems may be more appropriate and there may be DR-related program opportunities that would focus on the peak resource value a program-integrated energy management system can provide, and a broader customer base that would include smaller business accounts could be tapped.

Relationship of SLRP to Other Programs

There are non-pancaking provisions for SLRP as with other programs, so the inter-program relationship issues are the same as for other programs, in that customers need to be aware of the restrictions that apply in multiple program participation.

SLRP does not receive the marketing focus that other DR programs get, primarily because there has been little customer interest, utilities have found little value compared to promoting other DR programs and also because the strategic focus in demand response is on price-triggered programs.

SLRP Technology and Operational Considerations

SLRP does not need a communications system because there is no notification involved. Customers are interval-metered, of course, but otherwise there is little in the way of technology involved in this program.

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[8] Flat incentive, no penalty except program dismissal, presumably routine load scheduling, no notification hassles, etc.

Operationally, SLRP has had few customers and so there has been little operational experience.

SLRP Administrative Considerations

Being a very basic program without communications systems needs, SLRP has fewer administrative trappings than other programs. Its contract is simple as well.

Managers Interviews -- Rolling Blackout Reduction Program (RBRP)

RBRP Strategic Considerations

The Rolling Blackout Reduction Program is a relatively simple, targeted program, aimed at customers with at least 100 kW of backup generation. It is restricted to capacity (versus transmission) needs, so is somewhat more limited in its resource scope. Also, certain customer segments with double-contingency reliability requirements do not participate, such as hospitals and high-technology manufacturers.

Relationship of RBRP to Other Programs

Coordinating restrictions apply to RBRP as well as other programs, including taking precedence over DBP. RBRP is marketed along with other programs, primarily through account representatives. No issues were cited as being significant in this regard.

RBRP Technology and Operational Considerations

Interconnection equipment & parallel operation rules apply, as there must be a safe, "clean" transfer from the utility feeder to the customer's generator.[9] Event hours count against air quality restriction compliance requirements. Events are called utilizing two-way paging and cell phone messaging with an integrated voice response system for confirmation. The 15-minute notification period is believed to be sufficient for customers to start their generators, and periodic tests, which include partial load tests (limited due to air quality restrictions) are performed to ensure readiness. However, as there have been no events called a true operational situation has not yet been tried.

RBRP Administrative Considerations

The program has a simple contract, and settlement procedures are similar to those in other DR programs. There were no particular issues cited in this area for RBRP.

9.6.2 Customer Interviews for Three of the Five Programs

Fifteen customers in three of the programs were interviewed to learn about their participation experience. This included – 1) Seven customers of the traditional non-firm programs, spread among the three utilities, were interviewed; 2) five customers enrolled in BIP; and 3) three in

[9] Such rules apply to other DR programs where customer generation facilities are being utilized.

OBMC. BIP and OBMC customers were selected from utilities having customers in these program. While a small sample, the customer interviews yielded good information worth consideration as the programs evolve. The interview results are reported by program, prefaced by a discussion of findings and insights common to all three programs.

Common Findings and Insights Across Programs

There were some overarching considerations that seemed to cross program lines which included the following.

First, of particular interest to this evaluation is understanding the customers' reasons for dropping out of (or surviving on) traditional interruptible programs during the energy crisis. These interviews gave an opportunity to explore this matter with both survivors still on the program and dropouts who subsequently have enrolled in either BIP or OBMC. The findings point to a few key, inter-related areas:

- <u>Personal and institutional curtailment tolerance and event severity expectations</u>. Simply put, different people have different tolerances for taking risks; so, too, do businesses and other institutions. Survivors of the energy crisis curtailment events seem to have a higher tolerance for curtailments, or at least a greater willingness to forgo productivity and comfort to the extent necessary to continue participation. Thus, future program potentials analyses and marketing should, perhaps, attempt to segment by customer risk tolerance level as well as other demographics. Interestingly, customers *expect* fairly regular (though modest numbers of) events in the program. Certainly they are not complaining about the long "dry" period that has occurred since the energy crisis where year-round discounts or credits apply (as in traditional non-firm and BIP), but that was not their expectation of the recent past – they instead expected there would be two or three events each year.

- <u>Ability to adapt key operations during events</u>. Closely related to, and often a major influence on risk tolerance, is the physical ability to adapt operations to the program. Can equipment be shut down rapidly enough to meet 15- and 30-minute notices? Can appropriate staff spanning large campus situations be notified in time to switch off equipment? Can processes be shut down without wasting raw material or risking equipment maintenance problems? Both technical and behavioral issues affect customers' adaptability, so account management needs to take a broad view to helping customers adapt their operations. For this reason case studies, customer readiness meetings (where they can exchange "war stories") and other communications devices and venues are important to facilitate the exchange of experience among customers, as well as interact with program staffs.

- <u>Perceptions of what utilities are doing to address long-term resource adequacy</u>. Customers are willing to work as partners with their utility and make reasonable sacrifices *if* utilities are seen to be addressing underlying supply resource needs. Where resource adequacy more broadly is perceived as not being adequately addressed, customers become alienated and become less willing to participate in programs.

Second, continue working to improve and simplify program structures and processes. Some confusion concerning various aspects of program structures and processes was expressed by some interviewees. Their comments suggest there may be opportunities to further streamline programs. Such efforts are best addressed by account management and product development processes, because the information gained from the interviews is insufficient to fully define potential improvements.

Appropriate communications are critical to avoiding customers' concerns about whether they are getting timely communications and whether the utility really knows that the customer has acknowledged the notification. Even with the increased use of new communications methods such as two-way paging and cell phone contact, some customers remain unsure if such wireless communications are reliable enough.[10]

Administratively, contract agreements and other enrollment processes seem to be reasonably well-developed and customer-friendly, in large part because of the role account representatives play in helping customers size up their program opportunities and handle the enrollment paperwork. Yet, there may be some improvements that can still be made in the "back office," based on a few remarks about the length of time sometimes taken for the enrollment process, how baseline and impact measurements are performed, etc.

Third, customers want proactive relationships to build trust and visibility as well as assure program readiness. Account representatives are the key to this, and good representatives are highly valued by those interviewed. Often the customers found out about the program through a proactive contact by account representatives, and had much of the bureaucratic chore of enrollment handled by their account rep, which made a great service impression on the customer. Account reps also provide an operational "glue" that ensures readiness for the program season, timely event notification and trustworthy customer notice confirmation during events.

Thus, personal account management is critical, though other means can greatly augment the account representative's capabilities and productivity. One such approach that may be somewhat underutilized is interactive web sites where, for example, customers can log in to see if their event notice acknowledgement has been received back at the utility.[11] Some of this electronic augmentation of personalized account management has been developed for some programs, but there may be additional opportunities to facilitate information flows via interactive web sites that work in concert with field account management functions performed by reps.

Fourth, continue trying to find ways to lower rates in general. Beyond the usual appeal customers make for lower prices, try to make interruptible rates more economically attractive so that there is a lower bill that results in better payback for the efforts and risks customers take to participate.

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[10] One interviewee noted they keep four pagers active and still do not get the page sometimes when communications tests are conducted or the few actual events have been called in the last 2-3 years.

[11] This is a big reason why customers historically like remote terminal units (RTU), even if they are costly and clumsy compared to more modern wireless technologies: the customer knows their acknowledgement has been received. However, one interviewee stated that even the RTU is not without reliability problems, as discussed further below.

Customer Interviews -- Traditional Interruptible Programs

Five of the seven customers interviewed have been on their utility's program at least 10 years, with the other two on the program 5 or fewer years. This continuity in participation was helpful because interviewees could report on a longer history, and so address evolutionary issues as well as instant issues.

<u>Traditional Interruptible Programs -- Participation Reasons, Awareness and Enrollment</u>

Customers signed up for these programs to save money. They learned about their utility's program from their account representative, who often was proactive in making the customer aware of the program's availability. In most cases no significant barriers to signing up for the program were stated. Two comments offered concerning signup barriers concerned the issue of paying union staff during curtailments, and a concern over the baseline (which the customer was able to negotiate favorably upward).

The enrollment process was recalled as being fairly straightforward, and in some cases was handled almost entirely by the account rep (which help was much appreciated). Most interviewees expressed either medium or high satisfaction with most aspects of participation. Some did state their low satisfaction on some participation matters, so some further improvements probably remain. One customer stated they actually have not been participating the last couple of years, because changes in the program price structure reduced their economic payback to an unacceptable level. Otherwise, though, interviewees had either a medium or high level of satisfaction with the enrollment process.

<u>Traditional Interruptible Programs -- Operations</u>

Notification is a critical part of participation to customers and they require extremely high reliability in this process because they risk quickly losing any savings should they be unable to receive the notification message. One interviewee cited a recent incident where only two of their RTUs triggered, so it was not clear whether the event was official or not, when the event was over, etc. This same interviewee cited a need for utility staff involvement in such situations, to assist the customer's response. To that customer a 95 percent RTU (or other mode) reliability standard is not good enough. Other respondents were more positive in their feedback about notification, stating either medium or high satisfaction levels.

Customer satisfaction with event frequency and duration is clouded because there have been so few events for these programs in recent years. Interviewees understand this and so, often with somewhat of a tongue-in-cheek tone, stated high satisfaction with event dynamics. Similarly with discounts provided and penalties assessed: practically speaking, without events discounts are highly satisfactory and penalties are not assessed. But there were some concerns expressed: one interviewee stated concern that if they were one minute overdue on their curtailment they would get a full hour's penalty, and so that respondent expressed low satisfaction with the penalty structure from that perspective. Another respondent claimed to have negotiated a lower penalty,[12] which led to their being highly satisfied with the penalty structure. A third respondent frankly shared that in certain circumstances they deliberately choose to accept

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[12] Probably a reference to the one-time penalty waiver granted by the CPUC in 2001.

penalties by contracting for greater load reductions than they know can be achieved because they believe the overall net savings achieved make doing so worthwhile.

It is clear to these customers that events are either tests or for real, so there were no issues reported there.

In most cases, respondents stated that it is challenging to reduce load to the contracted firm service level. Sometimes they are within 5 minutes of being overdue on their response, and subject to penalties, before they settle into the full curtailment. One respondent stated they always seem to miss one or two actions and so have to scramble after their initial meter check to turn off the associated equipment. Two respondents said the difficulty depends on their plant operations: if not operating, no problem but if operating at high capacity events can present significant challenges unless there is a disciplined routine in place for such situations.

The specific loads affected mostly focus on process equipment and can include an entire plant shutdown in some cases. Kilns, large process motors, pumps and melting furnaces were examples cited by respondents.

Traditional Interruptible Programs -- Surviving the Energy Crisis

These customers survived the long, frequent curtailments during the energy crisis mostly by "gutting it out" and/or having business circumstances at the time which enabled them to continue on the program. One interviewee reflected that they survived because their plant was in a "slow" period at the time. That same person also shared that they considered installing self-generation instead of participating in the program, but that cost, emissions regulations, and *confidence that their utility would fix the underlying supply problems* got them to stay in the program. Another interviewee stated they decided to pay the penalties rather than risk product quality problems, inferring that they believed there to be a net payback from the rate discounts over the long term that justified paying penalties (even heavy ones) in the short term. A third respondent indicated that the penalty waiver they received was very important to being able to stay on the program.

Traditional Interruptible Programs -- Future Program Participation and Consideration of Participating in Other Programs

Most respondents indicated their intention to continue participating in the program. There were indications stated, however, that customers are wary and will be vigilant about changes in the program that would reduce the economic justification for their participation or increase their operating risks. Two respondents indicated their plants are either not operating now or will be closed soon, so the one is somewhat of a free rider and the other soon will be gone from the program. The one respondent who had stated they had dropped out of the program a couple of years ago said they quit because of too many, and too lengthy events and that they would have to see a better incentive package to re-enroll, because of the effort required in curtailment events. One respondent stated that their particular facility is able to stay on the program by split-shifting its workforce, but that a sister plant that runs 24/7 is unable to risk production interruptions by participating, and so does not. Another respondent stated their concern, that is affecting their position on staying on the program, is a lack of sufficient, proactive contact by their utility via account representatives and other staff, particularly when event notices are issued to ensure the validity of the notification and confirm the customer's acknowledgement and response.

It appears that alternatives to this program are not as attractive to the respondents who stated they had looked at other programs, though most respondents indicated they had not considered other programs recently. A couple of respondents said their business would not be eligible for other programs, and two stated that the incentives of other programs were not as good as those on the traditional interruptible program.

Traditional Interruptible Programs -- Conclusions

The interviews concluded by asking about overall program satisfaction and final comments. Respondents generally expressed medium or high satisfaction, with some reservations. The one respondent whose firm had dropped off two years ago continues to give the program a "low" satisfaction rating, confirming the common view that dissatisfaction lingers long and can be very difficult to turn around. Most respondents did not see a need for changing the program operationally, though there were the expected desires for lower impact levels or higher FSLs, and more generous incentives.

Customer Interviews -- Base Interruptible Program (BIP)

BIP Participation Reasons, Awareness and Enrollment

The five BIP customers interviewed cited cost savings for why they participate, though one respondent stated an altruistic need to contribute to the state's effort to avoid blackouts. They found out about the program three ways: by proactive account representative contacts, through a seminar they attended and by their initiating contact with their utility to inquire about ways to save money on their bill. Some have participated since the program's beginning while others are more recent participants. The respondents said the program has generally met their expectations, though one person said the program exceeded their expectations because there have been no events where a few were expected.

Barriers to participation were the need to ensure equipment integrity and critical production, including being able to continue service to the customer's customers. Two respondents consciously considered the likelihood of their being curtailed year to year, with one of them having gone so far as to study the resource adequacy picture in California in order to make his own assessment of the likely number and length of events.[13]

No problems were cited with the enrollment process, and the person who had found out about BIP at a seminar was pleasantly surprised with being able to sign up right at the seminar. Account representatives were cited as being helpful and making the enrollment process problem-free.

[13] He concluded, for 2004 and 2005, that there is a low probability of significant numbers or duration of events, and so has elected to remain on the program through next year.

BIP Program Operations

Notification is critical for this program, too. Two respondents cited specific issues concerning notification that may suggest helpful improvements to the notification process. One respondent noted they have pagers that don't always work, that they have email but they may not be in their office to see it arrive, and that the (one) phone call they get comes to their cell phone, which may not always be turned on. Thus, even with redundant notification means this customer has experienced times when test notifications are not getting through to him, and he is the central manager for event response. Another respondent had a similar story to tell, of getting monthly test notices but that those go only to one cell phone (which may be in use or turned off), or to a pager but then response by computer is required and they may not be handy to their computer. While this suggests continuing efforts to build a more robust notification communications capability, the fact that so many different "channels" have been employed already could mean there is simply a limit to notification success, and so other means must be explored to deal with situations where, for valid reasons, customers are not receiving notification in a timely manner or are unable to respond quickly enough because of extenuating communications circumstances.

Respondents had high satisfaction levels with event frequency and duration, as expected and consistent with traditional interruptible program interviewees because there have been no actual events. Similarly, satisfaction with incentive payments and penalties has been untested by events. The biggest fear of one respondent, which is probably on others' minds as well, is to not get the notification (at all or in time, due to communications failures) and then get penalized, even though the customer has not been negligent. That same respondent was, therefore, appreciative of the extra contact effort by their account representative when curtailments have become likely, to give the customer a "heads up." Consequently, this respondent expressed interest in a penalty waiver process, to provide a forum for them to troubleshoot and gain at least partial relief from undue penalties.

Respondents stated it is clear to them that test events are tests and not actual events, based on the messages being paged, for example. One respondent suggested it would be great to have a back-end confirmation of their having acknowledged receipt of the event notice, such as through an interactive web site. Such a confirmation function would help alleviate the fear of having only 30 minutes to respond, which time frame also includes the time it takes to confirm back to the utility the receipt of the notification.[14]

The 30-minute notice window is sufficient for those customers with automated response capabilities, such as powering down their PLC-controlled process motors: just program the EMS and then cut in the load control routine when the notice comes, and coordinate staff accordingly. However, those without automated response capabilities, particularly where the affected operations are far-flung, can present significant challenges to customers.

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[14] As stated by one respondent, they "pull the switch" on controlled loads first and THEN acknowledge the notification message variously by phone and internet, because of the time it takes to take equipment safely off line.

One respondent thought that a 4-hour maximum event duration is reasonable. Another wanted to see shorter maximum durations. Not having seen actual events, however, these opinions were speculative.

Response actions include shutting of air conditioning equipment, starting backup generators, switching off motor-driven production processes and shutting down the facility altogether.

<u>BIP – Participants' Previous Experience in Other Programs, Future Program Participation and Consideration of Participating in Other Programs</u>

One respondent stated they had been on the CPA-DRP program but had dropped off that a year ago because the incentives were not year-round as they are for BIP. They also indicated that the DRP program was slow to get incentives paid and that there was too much "red tape" compared to BIP. Three other respondents stated they had been on traditional interruptible rates previously but had dropped off those programs during the energy crisis because of an intolerable number and duration of events. Each stated they would prefer to go back on those traditional programs if they could (i.e., if the program were re-opened) because of the more generous incentives – but only if a reasonable number/duration of events could be assured.[15]

One respondent indicated they had considered and then enrolled in the CPA-DRP program in addition to BIP. They did this to get more savings on their bill. This same customer had been on the air conditioning cycling program but got off that when they enrolled in BIP.

All the respondents indicated they plan to stay on BIP to continue getting bill savings.

<u>BIP Conclusions</u>

Overall program satisfaction was split between medium and high satisfaction. Those stating medium satisfaction cited a desire for a lower rate (greater incentive) or longer notification times. Even an hour or 1-1/2 hours would be better than 30 minutes in one respondent's mind. Another respondent suggested the program could be improved by even greater efforts to assure reliable event notification communications. Still another respondent suggested a formalized procedure for advance warning of a potential event, to signal his firm to make preparations (perhaps on a day-ahead basis) for a possible event. He already receives this service informally from the account representative, which is what brought the idea to mind for a more formal procedure. Finally, a fourth respondent suggested developing a back-end confirmation capability so customers know their event notification acknowledgement was recorded by the utility; a penalty waiver process was also suggested by this respondent.

Customer Interviews -- Optional Binding Mandatory Curtailment Program

<u>OBMC Participation Reasons, Awareness and Enrollment</u>

The three customers interviewed about their OBMC experience all have been on the program since its inception. All learned of the program through their account representative, and all

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[15] One respondent, whose firm is an SCE customer, mistakenly believed that, because they are a direct access customer, they would not be eligible even if they met the "new load" conditions specified for SCE customers.

were concerned about the costs of being subjected to outages. One respondent stated his firm wanted to help the state deal with the energy crisis. Two respondents indicated no significant barriers to enrolling, while the third said they had purchased a backup generator upon seeing the results of their internal analysis that showed the cost of losing power once would be greater than the cost of buying a generator.

Enrolling presented few problems, with one respondent saying their biggest challenge was determining which loads to connect to their backup generator and so meet the load reduction requirements. Another respondent indicated there were what appears to have been program startup difficulties in setting up the notification process, but that that problem since has been solved.

OBMC Program Operations

The notification process that one respondent said had had problems initially is improved, he reported, and the other two respondents were satisfied with the process. No dissatisfaction was noted concerning even frequency or duration, which was expected given the lack of events. The reward of outage avoidance and penalties have not been tested, so opinions were either not given (being not applicable) or reflected a high level of satisfaction because there have been neither outages nor penalties.

Phone, pager and email all were cited as means to receive notification, with one respondent stating he goes to the utility web site to acknowledge the notification. It is clear in notices whether the event is a test or real, according to the respondents.

Two respondents indicated the short, 15-minute notification window is achievable because they turn on their backup generators (one of them also shuts down refrigeration equipment, which does not take very long and is simple). However, one of the two respondents stating they turn on their backup generators stated that it can be moderately difficult to meet the notification window because of synchronization requirements. The other respondent with self-generation stated it takes "less than an hour" to start up their generator, implying that they would attempt to anticipate events and put their generator into spinning reserve mode – though that may have implications for air emissions limitations. The third respondent stated that response difficulty depends on how busy they are – the busier the more difficult to respond.

OBMC Future Program Participation and Consideration of Participating in Other Programs

None of the customers interviewed had dropped out of other DR programs, so there were no issues to discuss in that regard. Neither have any of those customers interviewed recently considered other DR programs.

One respondent reported they reconsider program participation annually, so they weren't sure about remaining on the program, but the other two were more definite in saying they believed they would continue participating.

OBMC Conclusions

All respondents expressed generally high satisfaction with the program because there have been no events. One respondent indicated that, if they were in fact to leave the OBMC program that they would seek other programs in which to participate, to help avoid energy crises in the future. No additional comments were offered for program improvements.

10. CPA-DRP PROCESS EVALUATION

This chapter addresses issues relating to the implementation of the California Power Authority Demand Reserves Partnership (CPA-DRP) program. First, the goals and scope of the evaluation presented in this chapter are discussed. Next, we provide a program description and discuss the history of the program, followed by a discussion of issues investigated and evaluation results. We conclude with findings and recommendations.

10.1 CPA-DRP PROGRAM EVALUATION SCOPE, ISSUES, AND METHODS

It should be noted at the outset that the evaluation of this program was done during a time when the program was in a constant state of flux. As detailed later in this report, the very existence of the implementing agency (CPA) was in question throughout the summer of 2004, and has only very recently been resolved with CPA closing its doors and turning operation of the DRP program for next year over to PG&E. In addition, the exact terms of participation remained under negotiation over much of the evaluation period, so that even the specific aspects of the program being evaluated were sometimes difficult to determine.

This uncertainty was highlighted in an initial set of results regarding process issues related to the DRP program presented to the Working Group 2 Evaluation Committee in August 2004 (and submitted to the full working group September 2, 2004). These results were based on review of program documents and on interviews with utility and DRP program managers. In addition to integrating the findings submitted in September, this chapter provides the results of feedback obtained through interviews with program participants and the aggregators who market the program. Issues analyzed in this chapter include the following:

- Program status, participation and event history, including program changes and the effect of the uncertainty that has surrounded CPA and the DRP program
- Program strengths and weaknesses
- Customer perceptions regarding overall organization of the program as well as program attributes such as enrollment, compensation, notification, duration and frequency of program events, settlement, and other issues
- Likelihood of continued program participation and recommended changes.

These issues were investigated using interviews with utility staff responsible for DRP (3); representatives of CPA (2), DWR (1), and APX (2); aggregators (6) and DRP customers (10), including both direct access and bundled service customers; and active accounts as well as customers who dropped out of the program between 2003 and 2004. In addition, several representatives of industry groups that have encouraged their members to participate in the program were interviewed.

Customer interviews for the process evaluation were limited by how few customers were enrolled in the program and the difficulty of identifying participants who had dropped out of the program. Aggregators were asked to provide contact data for participants, but before doing so sought approval from the customers, which either was not provided or was simply delayed.

10.2 CPA-DRP PROGRAM DESCRIPTION AND HISTORY

The CPA, working with the California Department of Water Resources (DWR) and contractor APX, developed the California Demand Reserves Partnership (DRP) as a comprehensive demand management program in 2002 to "help mitigate the effects of volatile market prices and assure adequate supplies.[1]" The five-year program began operation July 1, 2002, with authorization to sign up to 1,000 MW of load, although for the past few years the cap has been set at 400 MW – consistent with the revenue requirements assigned to DWR for the program.

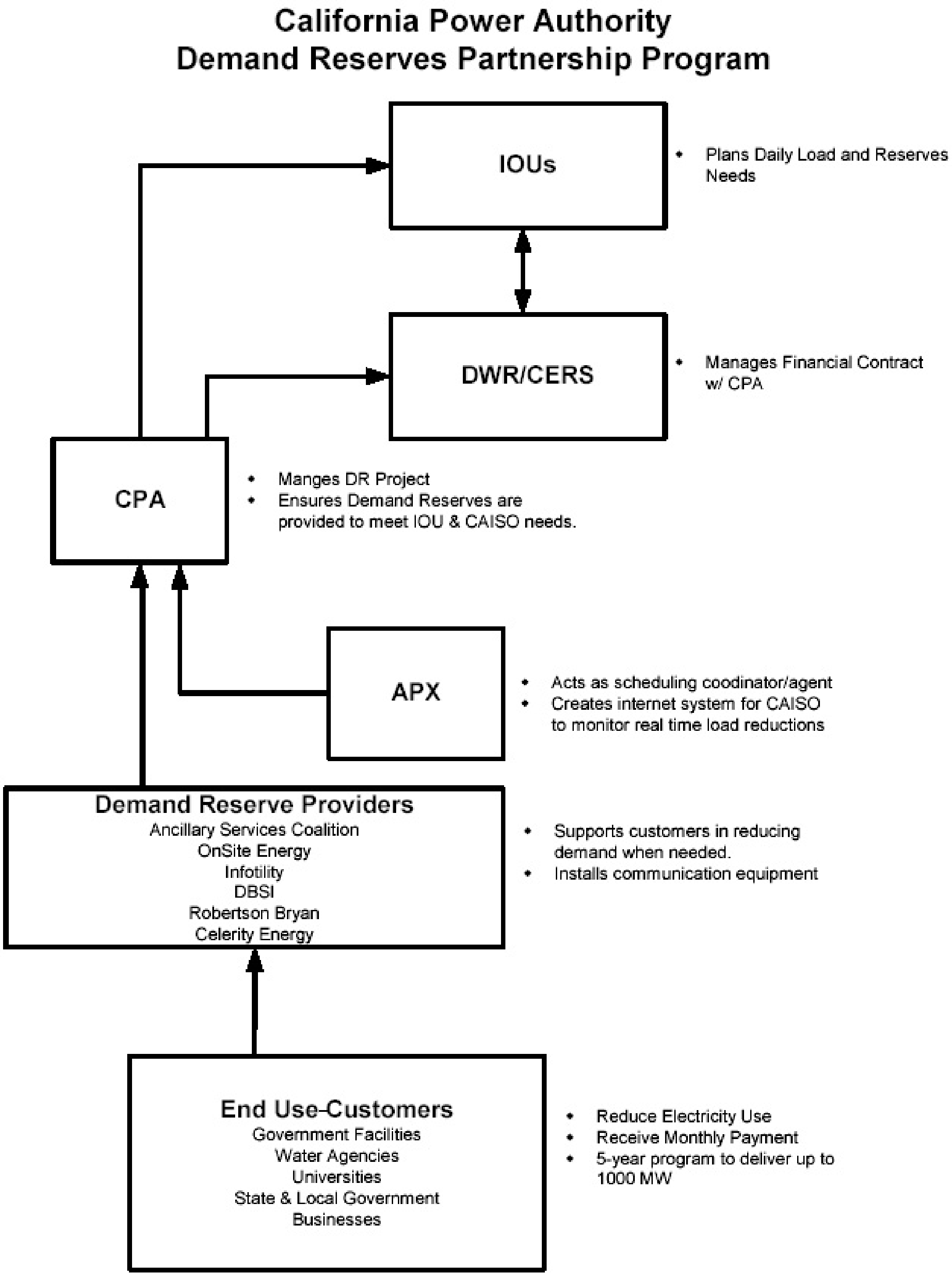
In the two years since its inception, the program has seen numerous and frequent changes: the amount paid for capacity provided through the program has declined steadily, while other conditions of participation have generally become more stringent, as discussed in greater detail below. More important, there has been a tremendous amount of uncertainty surrounding the continued existence of the CPA itself (which has ceased operations effective November 30, 2004) and of the nature of the program, with contract negotiations between the utilities, DWR, and CPA ongoing through the summer. Despite these constraints, the program represents a substantial DR resource, with a total of over 350 MW of load enrolled across the three utilities as of September 2004.

Current Program Organization

The overall organization of the DRP program through the summer of 2004 is shown graphically in Exhibit 10-1, taken from the DRP website, caldrp.com. While some of the organizations listed in the exhibit as aggregators are no longer active, the roles of the various players are accurately presented.

[1] DRP Program website: caldrp.com

Exhibit 10-1



As shown in the exhibit, the program has been managed and administered by the CPA, which was given this authority by the enabling legislation passed by the California legislature. CPA negotiated the terms of the program with DWR (which had been given responsibility for the procurement of power for the State in the aftermath of the energy crisis) and with DWR's subsidiary CERS, which is responsible for scheduling the power that DWR procures. To handle the implementation of the program, CPA retained APX, an independent provider of transaction processing services for wholesale electric power markets.

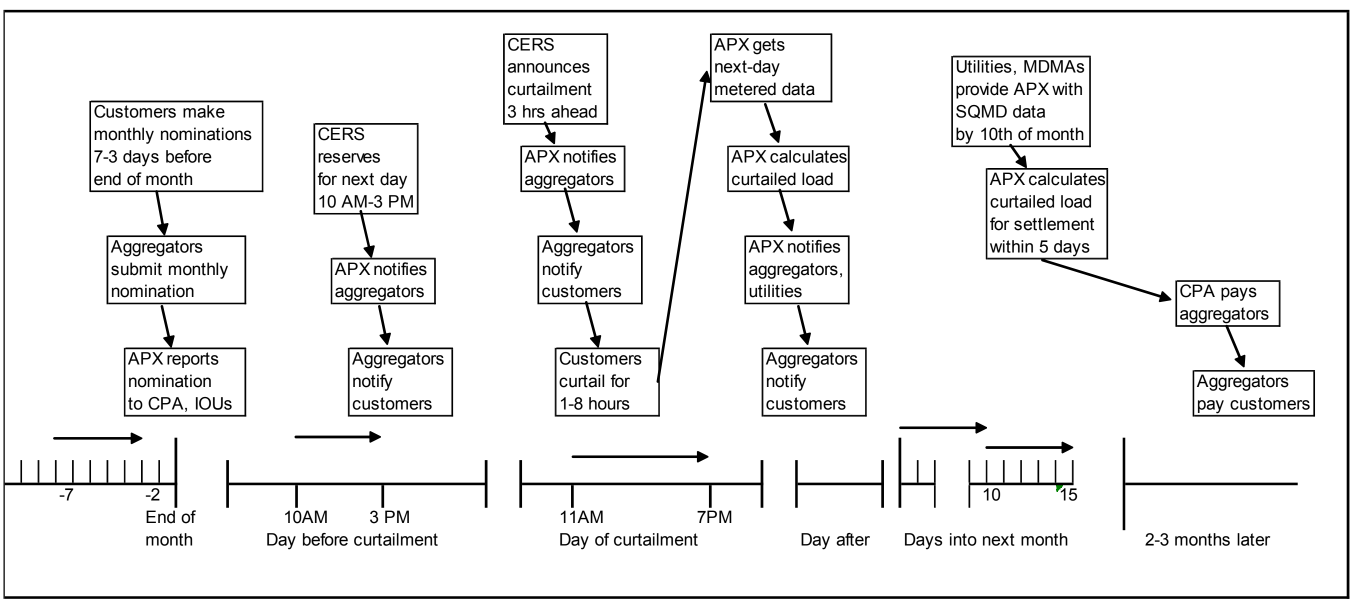
The DRP program was specifically designed to enable independent suppliers, called demand reserve providers or aggregators, the opportunity to offer demand response services in a competitive market, with resulting benefits to their customers and to the state overall. The utilities are, of course, involved because it is their direct access and bundled service customers who are working with the aggregators. The utilities have a role not only because they market the program, they must be able to integrate the reduction in load available from DRP participants into their own system planning. In addition, the California Public Utilities Commission (CPUC) had to approve the program and is involved in determining the funding that will be allocated to this program.

The involvement of so many different players clearly has implications for the operation of the program, as discussed below, and for the perception of the program among aggregators and participants.

Current Program Operation

The operation of the DRP program, summarized graphically in Exhibit 10-2, not only involves the large cast of players described above, but spans a significant amount of time associated with every individual event.

Exhibit 10-2
DRP Program Process Flow



The process begins when individual customers tell their aggregator how much load they will be willing and able to shed in the following month. This capacity nomination for a given month is done from 7 days before to 2 days before the end of the previous month. Customers tell their aggregator which of the "blocks" of time they are willing to be curtailed: 1-3, 1-5, or 1-8 hours. Aggregators combine these bids and submit them.

Not shown in the exhibit is a daily market that allows additions to the monthly bid two days in advance for any day of the month. In practice, most daily nominations have been the result of customers being signed up after the beginning of the month, and customers typically say they make a certain nomination at the beginning of the month and then stick with it. The exception would be if a participant has plant maintenance or another shutdown planned for a certain day, in which case they can make a daily nomination or nominations for the period the plant will be down.

When customers nominate for a given block type they indicate their willingness to be curtailed anywhere from 1 hour to the maximum (3, 5, or 8 hours), for a total of up to 24 hours per month. This represents a change from the 2003 program, when customers could specify that they were willing to be curtailed for a 2, 4 or 8-hour block. CERS could choose when to curtail, but had to curtail for the full number of hours specified. Under the new rules, participants can be curtailed as little as 1 hour per day, but must be able to curtail for at least 3 hours. Thus, the maximum curtailment of 24 hours per month could mean numerous small curtailments, not the three 8-hour curtailments that some participants could plan for as their worst-case scenario last year. This new requirement added considerable flexibility for the dispatching authority (CERS), but raised the potential inconvenience and business impact for participants, some of whom dropped out of the program as a result.

Customers receive two types of payments from their aggregator for their participation.

- A capacity payment for the nominated capability to reduce demand, whether or not the customer is actually asked to reduce usage. The more a customer is willing to reduce (i.e., the higher the monthly plus daily nomination), the higher the retainer payment.

- A performance payment ($80/MWh) that is tied to the actual amount of demand reduced.

DWR determines how much it will pay for capacity, but the actual payment a participant receives may vary by aggregator depending on the package of services provided and the contract negotiated. The amount of the per-MW incentive offered by DWR for capacity nominated during the summer months (June-September) decreased from $14,000 a month in 2002 to $8,500 in 2004. Non-summer month capacity payments are minimal: $250/MW/month in 2004. Customers are not happy about the decline, but so far none have dropped out of the program because of it.

As in 2003, for the 2004 program, before calling on participants to reduce the demand on a given day, CERS must reserve the following day's interruption. The reservation must be made by 3 PM on the day before the planned event. For 2004, however, this did not commit CERS to actually call (and pay for) a curtailment. In effect, this has effectively turned the program from a day-ahead to a day-of program.

The curtailment reservation is issued from 10AM-3PM the day before the event, including a definition of which products or blocks are being reserved. Rather than deciding which hours and which blocks to reserve, CERS has typically reserved all 8 hours in all regions, which enables them to dispatch any of the 3 program types the following day. This "reservation" for next-day events was done for most of the summer – all weekdays from early July on.

When CERS decides on the following day to go ahead with the curtailment, it notifies APX at least 3 hours ahead of the event. APX then automatically notifies the aggregators, who in turn notify their customers. Within a customer organization, the point of contact may then relay the message to operators of individual facilities.

In most cases, participants will have developed a detailed curtailment plan that corresponds to their nominated capacity. While CPA participants who have access to websites such as SCE's Energy Manager have the ability to track their baseline and their current usage, aggregators say many of the participants in the program do not have the ability to view their energy usage in real time – particularly if they are aggregating multiple smaller accounts. Instead, the participant's utility or Metering Data Management Agent (MDMA) provides data to APX on the customer's usage the next business day. APX conducts a preliminary review of the electricity usage recorded by the customer's meter from the data provided by the utility or MDMA, then calculates the demand reduction based on a baseline defined as the average demand over the past 10 business days, with a scalar adjustment for the three hours prior to the notification. The results are posted on APX's web site the next day and can be accessed by aggregators, utilities and other authorized users.

The final calculation of reduced load based on settlement quality metered data (SQMD) is not conducted until after the end of the month. The utilities provide SQMD to APX within 10 days of the end of the month; APX then has 5 days to turn that around and provide the basis for settlement. The CPA and DWR use this calculation to determine how much is paid to the aggregators, who in turn pay their customers in accordance with the terms of their contract.

10.3 CPA-DRP PROGRAM PARTICIPATION AND EVENT HISTORY

One of the distinguishing characteristics of the CPA-DRP program is that participation is dominated by relatively few large participants. Most aggregators have only a few customers, although many of the participating customers have multiple accounts, and have a substantial total load.

- DWR is the largest participant in the program and acts as its own aggregator. DWR's pumping facilities account for about 200 MW of PG&E's 218 MW program load and for over half of the total load enrolled in the program at the peak of the summer.

- Other participants include water agencies, cold storage facilities, university campuses, retail chains, and manufacturers. Since aggregation is supported by the program, some end users are able to combine a number of relatively small individual accounts into a capacity nomination in excess of 1 MW.

The enrolled load reported by the utilities to the CPUC for 2004 is presented in Exhibit 10-3.

Exhibit 10-3
DRP Program Load

Month / Utility	30-Sep-04		31-Aug-04		31-Jul-04		30-Jun-04		31-May-04		30-Apr-04		30-Mar-04		28-Feb-04		31-Jan-04	
	MW	Accts	MW	Accts	MW	Accts	MW	Accts	MW	Accts	MW	Accts	MW	Accts	MW	Accts	MW	Accts
PG&E	218	126	215	67	214	63	200	12	224	20	224	20	210	23	245	66	245	66
SCE	143	89	139	87	117	73	13	5	0.6	2	3.3	7	3.3	7	3.3	7	3.3	7
SDG&E	4.3	24	3	21	3	21	3	19	0	0	0	0	5.5	13	5.5	13	5.5	13
Total	365	239	356	175	334	157	215	36	225	22	227	27	219	43	254	86	254	86

First, it should be noted that the number of customers reported represents meters rather than customers, due to the aggregation of meters that is possible through this program. As mentioned previously, DWR is by far the largest participant in the program, with 16 accounts and 200 MW.

Second, it should be noted that the amount of DRP load reported is not what is available in any given month. What is reported is typically the "registered capacity of the meter." This amount is usually what the customer works out with the aggregator as the maximum they would be able to realistically curtail; this is the amount registered for the program with APX, and APX subsequently reports that MW figure along to the utilities – who report it to the CPUC.

What is significant is that the registered capacity is generally much more than the amount that customers nominate – even if daily nominations are taken into account.

- SCE, for example, reported 143 MW of registered capacity for September, but the combination of monthly and daily nominations actually available when the program was called on September 23 was 30.9 MW. SCE plans to begin reporting nominated capacity in January 2005.

- Similarly, SDG&E customers had a registered capacity of 4.3 MW for September, but the maximum combination of monthly and daily-nominated capacity at any time that month was 1.7 MW.

- In PG&E territory the difference between the registered capacity reported to the CPUC and the capacity nominated is much smaller on a percentage basis, since DWR bids the full registered capacity of its accounts in the monthly nomination.

Note that nominations have generally been very conservative, both because of the overall uncertainty surrounding the program and because the 95 percent compliance requirement has led aggregators to encourage customers to nominate no more than they can comfortably commit to. While it is likely that DRP participants will increase their monthly nominations as they gain experience with the program, the non-DWR load actually available through the program is currently well below the amount shown in the CPUC report.

The extent to which the nominated load actually leads to reductions when called is also difficult to confirm, since there have been relatively few events for the CPA-DRP program. In 2003, the first full year of operation, there were seven events, mostly tests. In 2004, there were eight events according to data compiled for the utilities by APX; nevertheless, most of the customers interviewed reported only one test event and some reported none at all. This is because tracking DRP events is complicated by the fact that the program can be dispatched for different congestions zones as well as for different products; that is, only the "1-3 hour" blocks might be called for one of the congestion zones.

There were three actual curtailments in the congestion zone covering the part of PG&E's territory that has the greatest participation, with one event each in July, August, and September. For these events, PG&E alerted CERS that it anticipated prices high enough to trigger the program (i.e., above $80/MW), and CERS subsequently called the events.

While detailed curtailment data were not available, a representative of CERS said that the overall level of attainment is usually about 90-95 percent. He noted that as many as 50 percent of the individual meters enrolled in the program do not change their usage at all, but that users who aggregate numerous accounts into a single nomination generally comply on that aggregate level.

10.4 CPA-DRP RESULTS

Overall Organization

Program managers as well as customers see the fact that there are a number of players involved in the program as both a strength and a weakness. One of the most compelling benefits is that competitive forces help to ensure that customers have a choice of a variety of product offerings built around the DRP program. Several instances of this were cited by program managers, aggregators, and customers.

- One program manager noted that all the aggregators appeared to have worked out an approach to penalties for failure to curtail when promised that did not involve out-of-pocket charges to participating customers – a real concern to many of the customers targeted by this program.

- A program participant described reviewing the offerings of several aggregators and selecting the one with no fixed fees; that is, the aggregator was paid only if the customer was paid.

- Some aggregators combine their marketing of participation in the DRP program with advanced automation technologies that enable customers both to automate response to program events and to aggregate the actions of smaller individual accounts.

While DWR sets the overall amount of the per-kW capacity payment and the per-kWh energy payment to the aggregators, the allocation of that payment to the customer varies according to market forces. In addition, there are no fixed minimums for participation; aggregators make their own choices regarding what customers to approach so that the cost involved in managing a customer does not exceed the benefit of adding them to the program.

There are indications that the utilities, too, would like to be able to offer this program to their bundled customers. According to account managers and some aggregators, there are customers who prefer to work with their utility and the account manager with whom they have an established relationship. The manager of a refrigerated warehouse recalled being ready to participate in a predecessor of the current DRP program several years ago, having signed a memorandum of understanding with their utility account rep, only to find that the utility would be unable to offer the program. They subsequently signed with one of the aggregators and have been happy with their participation.

The disadvantage of having multiple players is that it adds to the complexity of program operations. As noted previously, program participants need to be put on a calendar month billing cycle, which means utilities have to change the read dates for all their bundled customers, while DA customers must arrange similar changes with their MDMA. Both utilities and MDMAs must also provide metered data to APX to provide a basis for settlement. The logistics of coordinating the activities of a variety of organizations increases the likelihood of miscommunications and may have contributed to the delays in program payments reported by aggregators and customers.

In addition, there have been conflicts (some would say turf battles) between the different players – both between the DWR and CPA and between the utilities and DWR and/or CPA – over how contracts should be interpreted, how the program should be operated, and what the specific terms of the program should be. The change from a day-ahead to a day-of program in 2004, for example, was initiated by DWR, as were the reductions in the per-kW payments and the changes in the program "blocks" customers could nominate, while CPA resisted these moves. Program managers from the utilities also noted that there were frequent conflicts between CPA and DWR – in part because of their different missions and different perspectives on the program: while CPA was seeking to build DR capability, DWR tended to view the program purely as a power procurement activity.

Several aggregators also noted that having two government agencies involved in the program would inevitably lead to conflicts. Comments from aggregators included:

- I think that one of the biggest issues is that all of the acronyms are trying to protect their jobs; obviously there are way too many cooks in the kitchen. Everybody seems to be spending a lot of time trying to make their part of the program the most important part.

- There are too many organizations involved -- all these government agencies with their own agenda. The goal should be to free up capacity.

- It was clear from CPA that CERS is completely indifferent to whether the program exists.

In the past, the utilities have been somewhat "out of the loop" regarding information related to the program; CPA has reported the enrolled load, as described above, which utilities then include in their reporting of DR program load, but the utilities were never able to find out just how much of the load was being delivered for specific events. The process of reporting information appears to have become smoother, although the utilities still do not know precisely how much DRP participants in their territory curtailed relative to their nominated capacity.

Utilities would also like to have greater control over the DRP load within their service territory. While DWR is responsible for dispatching the DRP load, they are increasingly responding to utility requests to call the program for specific areas. This past summer PG&E several times asked DWR to call the program in one zone in their territory because it appeared that the spot price was going to go above the $80 per MW that DRP participants would be paid if they curtail. The utilities may begin to dispatch load directly before next summer's DRP program.

Program Eligibility, Conditions, and Incentives

The DRP program was, until recently, the only price-based demand response program available to direct access (DA) customers (note that DA customers may participate in several of the IOU's interruptible programs but these are considered reliability not price-based DR by the CPUC). In addition, it provides the opportunity for multi-premise accounts to aggregate their load – which they have not been able to do in other utility DR programs (although utilities' have just proposed allowing DBP customer aggregation in the October 15, 2004 filings).

Both customers and aggregators say that one of the greatest selling points of the DRP program is the fact that it pays a monthly reservation payment for the customer's commitment to shed load when called. Interview respondents pointed out that there is a cost involved in being ready to participate even when the program is not called, and that alternative DR programs (i.e., DBP) offer no incentive to help offset this cost. Moreover, the payments involved have been more substantial than those offered under other programs, even though they have declined from up to $14,000/MW per month for the summer months the first year to $8,500/MW per month this year.

Customers and aggregators both decry the decline in incentives. A representative of DWR said, however, that the earlier, higher payment was based on the assumption of customers offering anywhere from one to the full eight hours of curtailment; since most do not offer to curtail for that long, DWR reduced the amount of payment to reflect the value to the system.

Per-event payments have not been a major issue, since there have been few events and the amount of the payment is only 8 cents per kWh. The bigger concern among customers is that failure to deliver at least 95 percent of the nominated load over the stipulated time frame results in the full loss of the capacity payment. It should be noted, as described in Chapter 6, that the 95 percent level is well within the range of "noise" from different baseline methods. Aggregators and customers both thought that a graduated reduction in payment would be more equitable, with full loss of payment only occurring if the customer failed to deliver, say, 50 percent of the nominated load. Aggregators say one effect of the new 95 percent requirement has been to make customers much more conservative in how much load they commit to at the beginning of each month. This may change, however, as customers gain experience with the program.

Other issues that have motivated customer participation are reflected in comments offered by program participants.

- Our reasons for participation were: 1) the monetary incentives; 2) the Governor's executive order regarding public buildings; and 3) our automated ability to operate a campus-wide load shed.

- A big reason was the incentive, but we're also a public agency so we have to have the best rate and be environmentally friendly.

- We felt like we could respond, but more important, if we weren't able, there's no penalty. Lack of penalty is a big thing. Most of our load is already on one of the utility rates or programs, but there's a small portion on firm, and we try to participate with that.

- Overall DRP was the best deal. I think a couple years before DRP we were signed up in the DBP, but that's kind of a nonstarter. First, you only get paid when you shed load, and not very much, and the other thing is the old DBP required more work. [2]

Barriers to participation have included the overall uncertainty surrounding the program, including CPA's status and the changing program requirements. Aggregators pointed out that the uncertainty made their marketing job substantially more difficult, and that the reduction in incentives and in notification time didn't help.

- With the uncertainly this year, we didn't know what to offer.

- I couldn't tell what was going to happen, so you had uncertainty plus complexity; too many fingers in the pie.

- The lower price is one barrier; second is lack of simplicity. It's very complicated, with too many rules, too many "gotchas". One customer lost $3,000 because they turned the switch 10 minutes before the start of curtailment, so their 15-minute interval data showed high usage and they were out of compliance.

- For some customers, it was an adjunct to what they were doing, so with the price reduction and the new rules they said forget it, it's just not worth it.

Participants (and potential participants) also commented on the uncertainty they faced when they considered signing up for the program.

- Certainly when we got started I was a little skeptical. The rules were complicated, there was no final official statement of how the program was supposed to work; a lot of the details were word-of-mouth.

- There was so much strife in the middle of the summer, (the water agencies) said, "look, I'm not going to participate because I put the system at risk, unless it's absolutely safe on the payment side, I'm not going to get involved."

Given the importance of the level of uncertainty in discouraging participation and making program marketing more difficult for aggregators, we recommend that no changes be made to the program before the next program year. Instead, the focus should be on creating organizational and program stability in a time frame that allows marketing well in advance of the summer 2005 season. This will provide a better indication of the level of interest in the program as currently designed. If response proves to be less than expected or there is a

[2] The customer's reference must be to a predecessor program, as the current DBP has only been in operation since late 2003 and 2004.

decision to build more capability for this program, it may be appropriate to change other program features to encourage greater participation. For now, however, stability is the highest priority.

Program Enrollment Process

As noted previously, in order for settlement data to be processed consistently, program participants need to be put on a calendar month billing cycle, which means utilities have to change the read dates for all their bundled customers, while DA customers must arrange similar changes with their MDMA. The result has been that it has taken, in some cases, months before a customer could be enrolled in the program. The lengthy enrollment process, coupled with the uncertainty of the program's fate and design in the spring of 2004, severely hampered the ability of aggregators to sign up customers and have them fully enrolled in time to participate this past summer. Aggregators offered the following comments regarding the time to register meters and enroll customers:

- The meter registration process has been slow. It's gotten better but the aspects we face are the third party authorization that's appropriate for that utility, getting the current one, passing originals not copies, and so on. Customers have to do it a certain way. If you don't do it exactly right it takes long.

- It's pathetic that it took so long to get a customer registered; took months in some cases. It was a situation where the people actually responsible to get it done had no accountability. There was lots of finger pointing.

- Going through the (enrollment) process has been a nightmare (for a multi-store retail chain that spans several service territories).

Customers were less concerned about the delay, but also commented on the length of time required for enrollment.

A utility program manager pointed out that the enrollment process itself is simple, and requires only a two-page third party agreement – an industry standard contract -- with the utility. She said that problems arose this summer because participants often did not provide the required data or fill out the required forms correctly. Because there are so many parties involved in the program, correcting errors and omissions often meant going back through the chain of players to get the accurate information from the customer. In addition, some participants may have encountered delays because utilities no longer had funding to supply RTEM meters toward the end of the summer.

Notification and Curtailment

As noted earlier, DRP became a *de facto* day-of program in the summer of 2004 with the change from a binding to a non-binding next-day curtailment reservation by CERS. Since the reservation could be cancelled the day of the reserved event, participants did not know until 3 hours before the event whether or not they would be called upon to curtail. CERS issued reservations on essentially every weekday of the summer, meaning that participants could be called upon to shed load on a same-day basis.

- Several customers objected to this daily reserving of events, calling it a "cry wolf" approach. Some said they had stopped doing anything to anticipate the reserved events, preferring to wait until an actual event is called. One or two said they asked their aggregator to stop sending them the daily notification messages about reservations; others said they simply ignored them and looked for the same-day announcements.

- A few participants dropped out of the program because of the change in notification. One noted that: "With the day-ahead, my reasoning was that if we knew early on the previous day then even though we take a big hit at least we could plan some other maintenance activities, etc. But we have to do that before 3 in the afternoon so they can come in the morning to do routine maintenance. That advance notice was important."

Most of the other participants interviewed obviously had found a way to handle the shift to same-day notification. Some said they can reduce their load by the amount at the touch of a button; others need to manually shut down equipment.

Knowledge of how to reduce their load typically is not a problem for these customers. Most are knowledgeable about their operations and what they can curtail for how long. In addition, aggregators often provide technical assistance or advanced equipment to develop a curtailment approach. Specific strategies mentioned by end users include the following:

- Refrigerated warehouses simply turn off their compressors for several hours, noting that they can "go for up to 4 hours. We might be able to go a little longer, but we want to play it safe."

- Water districts reduce their pumping and rely on storage. A consultant to the Association of California Water Agencies (ACWA) says that water agencies have the potential to increase their demand response participation by 500 MW, and even more with added investment to improve storage or use of alternative pumping technologies.

- Some universities, retailers, and other commercial buildings rely on automated systems to cut back lighting, cooling and other end uses in a controlled manner.

Customers did mention constraints on how long or how often they could curtail, either in consecutive days or in the length of individual curtailments. While the participant's nomination sets an upper bound on the length of individual curtailments of 3, 5 or 8 hours, CERS is not obligated to call that maximum amount, so customers could theoretically face a large number of short curtailments. The maximum number of hours (24 per month) is seen by some as providing some protection, but that perception is based on the assumption that curtailments would be the full length allotted (i.e., three eight-hour curtailments), which may not hold, since DWR could, for example, call on them to curtail for 2 hours 12 times in a month under the changed program rules for 2004.

Some customers' say it's not shutting down quickly that poses a problem; it's getting the facility back up to full operation after the event. One customer who has dropped out of the program noted that it was relatively easy to shut their research facility down in an hour, but that it took the better part of a day to bring it back online. For this customer, the new program rules that allowed repeated curtailments of as little as one hour raised the level of risk associated with the program beyond what they could handle, and they took their 10 MW of load reduction out of the program.

One of the changes to the program for 2004 was that customers must shed at least 95 percent of their nominated load to be considered in compliance and receive any credit. Both aggregators and customers found this very restrictive, suggesting that some sort of sliding scale would be more appropriate, with payment disappearing altogether only at a much lower level of performance. The following comments were offered:

- Newer customers were really concerned, saying, if I deliver 950 kW out of 1000 I'm not going to get anything? So customers have become more conservative.
- I would like to see them loosen up on the interpretation of the 95 percent. It should be proportional and maybe a cut off below, say 40 percent.
- They have that 95 percent rule right now which is unreasonable.
- If you look at the penalty phase you have to be within 95 percent or else you loose everything. What troubles me the most is that if, day before curtailment you lose a contract or have a piece of equipment go down so your load drops from 5 to 4MW and if curtailment comes down, you can't curtail down to 3.
- This year customer has to be at 95 percent performance to be compensated. What that forced us to do is be more conservative with our nominations.

The burden created by the 95 percent requirement is aggravated by the fact that many DRP customers do not have access to the 10-day baseline or their real-time usage, which may lead them to over-or under-respond. One customer said "we don't have real time 'preview' capability for baseline average load condition. It's only viewable at the time of settlements – so if there's haggling, it's after the fact."

As with other program requirements, there may be a case for changing the notification time frame and the criteria for compliance if more customers need to be attracted to the program. In the meantime, however, aggregators should be given the opportunity to see how much they can do with the existing program within a stable organizational and contractual framework.

Settlement and Payment

While the aggregators receive next-day feedback regarding the performance of their customers when curtailed, the basis for payment is the settlement quality, cleaned and validated metered data that the utilities must provide to APX by the 10th of the month. There have, however, been problems with the transfer and interpretation of data, so that determining the actual amount of curtailment has proven difficult. As a result, the energy component of the payment received by customers has often been delayed.

Even the more substantial capacity payments due to customers often do not arrive within the expected time frame; this is one of the primary causes for customer and aggregator dissatisfaction with the program. In theory customers are supposed to receive payment within several weeks after APX calculates the load shed during curtailments – even sooner when there have been no events, but several customer said that it had taken months after the end of the month in question before they were paid. Customers offered the following comments:

- Very slow on payments! We don't know what settlements are for events 2-3 months ago.

- Our chief complaint is that (the payment process) is very slow. We're just being paid in November for July. This process needs to be substantially improved.

- It takes pretty long. Probably months before you get paid; it was at least 2 to 3 months after the end of the month.

- We haven't gotten paid yet for this summer (as of early November).

There have been some problems with metered data (for example, an issue with the change from daylight savings to standard time that created confusion over which hours had been curtailed), but APX has generally been able to provide the required data by the 15th of the month. The aggregators then have to verify the data before submitting an invoice to CPA, which in turn invoices CERS, which pays CPA, which pays the aggregators, who pay their customers. Delays appear to be inherent in this billing cycle, and their cumulative effect may be contributing to the overall length of time that customers have to wait for their checks.

Regardless of the reasons, every effort should be made to expedite payment to the aggregators so that they can pay their customers. Delays in payment and settlement problems with previous programs have caused many water agencies to view programs like DRP with suspicion, according to a consultant to ACWA. Participant experiences with prompt and accurate settlement (as well as other aspects of program implementation) are needed to generate positive "word-of-mouth" and help rekindle interest in DRP among these and other customers. As one respondent summarized it: "if we have multiple years of stability in the program and we have people at conferences who can say it went well – the verification was correct and we got paid and they haven't messed around with it, that would make a big difference."

Satisfaction, Future Plans and Program Outlook

Despite their reservations about individual program elements, most of the participants interviewed are satisfied with the DRP program overall and with the aggregators who provide it to them. None said they did not intend to continue with the program next year; several said they might add new accounts or expand their participation. Comments included:

- We were very satisfied. We didn't have to do anything and got paid every month.

- This program works well for us and the level of payments is good, though $10/kW is a more desirable level. But there is the uncertainty issue - is the program changing, and if so how?

- We'll participate again. Yet, we would be much more aggressive if payments were timely, and if more events were called.

- We've chatted about adding some meters; we may be able to increase, but we want the plant operators to be comfortable with that.

A couple of customers commented on the decline in the incentive and the possibility of increased penalties when discussing their future plans:

- This year (our satisfaction) was medium; two years before that it was high. If what you get goes down, it's hard to be just as satisfied.

- It's a good program but they've reduced the incentive each year. It gives me heartburn; people never want to pay for demand response unless they're going to use it all the time.

- We're concerned that they're going to really make us pay for not curtailing. Raise the penalties and reduce the amount they pay.

Most of the aggregators interviewed expressed confidence that they would be able to attract new participants to the program now that program provisions had been finalized. In addition, some said that the inclusion of ancillary services (load available with only 15 minutes notification) in the CRP program next year could expand participation.

To the extent that the CPA's demise threatens to undermine the stability of the program, it is imperative that the transition to a new program manager takes place as quickly as possible. PG&E has been given until February to come up with a detailed plan to operate the program. A quick response to that plan and development of a final program is essential if the DRP is to continue the momentum that it appears to have built over the past several months.

10.5 FINDINGS AND RECOMMENDATIONS

The following are key findings of the DRP process evaluation.

- The DRP program in 2004 faced an array of obstacles that would appear to make it a severe marketing challenge: the price paid to participants had declined for each of the past two years, conditions of participation had become more difficult, the sponsoring agency had been on the verge of going out of existence, and there were no formal contracts in place describing just what participants are expected to do and when or how they are expected to do it. In spite of these obstacles, the aggregators who are responsible for finding and enrolling participants managed to attract a number of customers – both DA and bundled – who remained with the program throughout a potentially disastrous summer.

- The program has gone through frequent changes since its inception; uncertainty has discouraged many customers from participating and made it very difficult for aggregators to market the program. Program managers, aggregators and customers agree that the most urgent need now is to bring stability to the DRP program; who will run the program, and what will be the payment and other operational terms of participation. The program will still be complex, but most customers say they are likely to stay with the program if stability can be attained. Most of the aggregators interviewed expressed confidence that they would be able to attract new participants to the program now that program provisions had been finalized.

- Participants were strongly motivated by the capacity payment offered through the program, noting that this feature distinguishes the DRP program from other options such as DBP. Other features attracting customers include the eligibility of DA customers and the lack of out-of-pocket penalties under the program terms offered by the aggregators. Almost all participants complained about the decline in the capacity payment over the past two summers, and a few said further reductions might call their participation into question.

- Acting as its own aggregator, DWR itself dominates participation in the program, accounting for over half of the load in the program. Opportunities appear to exist to expand participation by other customers, with particular emphasis on industries such as water agencies that have significant untapped potential but are reluctant to participate until the program has demonstrated stability and effectiveness. Greater utility involvement in the program may also increase the pool of customers willing to participate.

- Having multiple players adds to program complexity, but competition among aggregators appears to work to the advantage of customers; a specific example is the extent to which aggregators structure agreements with customers to minimize exposure to out-of-pocket costs – whether for penalties or fixed fees associated with the aggregator's services.

Based on the results of the evaluation, we offer the follow recommendations to enhance the program's effectiveness.

- Given the importance of uncertainty in discouraging participation and making program marketing more difficult for aggregators, we recommend that no changes be made to the program before the next program year. Instead, the focus should be on creating organizational and program stability in a time frame that allows marketing well in advance of the summer 2005 season. This will provide a better indication of the level of interest in the program as currently designed. If response proves to be less than expected or there is a decision to build more capability for this program, it may be appropriate to change other program features to encourage greater participation. For now, however, stability is the highest priority.

- Third party aggregators serve a valuable function in marketing the program, assuring customers of a range of options, and providing technical assistance. They should continue to play a key role in the program even if the role of utilities in managing and dispatching the program increases.

- Payment for nominated load should remain at current levels, both to provide continuity and because participants place a high value on the availability of the capacity payment. Other program requirements (e.g., notification, higher compliance required, less control over curtailment length) are difficult for some participants, but there is evidence of ample interest under existing terms if there is stability in the program and the incentive.

- As with other program requirements, there may be a case for changing the notification time frame and the criteria for compliance if more customers need to be attracted to the program. In the meantime, however, aggregators should be given the opportunity to see how much they can do with the existing program within a stable organizational and contractual framework.

- Utilities should report the amount of program capacity nominated. Monthly nominations plus the peak daily nomination, taken together, represent a better indication of the magnitude of the DRP program as a resource than does the registered capacity currently reported.

- Settlement delays may be due to the many players involved, but the process needs to be streamlined so that aggregators and customers can be assured of receiving their payment within 60 days after the end of the month.

11. REVIEW OF NON-CALIFORNIA DEMAND RESPONSE PROGRAMS

This chapter presents the results of a review conducted of demand response programs throughout other parts of the United States. It describes various features, trends where noticed and, from a sample of program managers, a discussion of lessons learned from program experience. Keys for program success round out the chapter. Tables detailing the program review tabulation are included as Appendix F.

11.1 SCOPE AND ISSUES

The experience of others with demand response programs may provide useful insights to programs in California, and so help maximize California programs' impact and cost-effectiveness. Toward that end, a task was commissioned to conduct a review of DR programs around the United States. The research team developed an extensive amount of data by building upon previous compilations of program features. Program veterans' insights on the history and future evolution of DR programs were obtained through personal interviews conducted via telephone.

The objective was to gather information with which to address program life cycle issues affecting the successes and failings of DR programs. Issues which this information can help better understand span the entire life cycle of programs:

- In program design, how are successful program features structured?
- Operationally, what program delivery factors influence program success, and what points of leverage are there when implementing programs?
- What lessons have been learned around the industry that can guide future program designs and operations?

The scope of activities undertaken to address these issues included:

- Identifying DR programs and organizations from existing reports and DR program compilations, recent presentations at relevant conferences, and utility web sites and program materials.
- Compiling feature data on a variety of programs offered by load-serving entities and independent system operators (i.e., both wholesale and retail programs). This included information on significant historical programs not previously in the DR spotlight: for example, WE Energies, Cinergy, Xcel Energy (in particular one of its precursor companies, Northern States Power Company), Ameren Energy and Kansas City Power & Light.
- Interviewing a sample of program managers based on program similarities with California programs and the likelihood of the program managers providing useful insights.

In all, feature data on 66 programs offered by 30 organizations were compiled from a variety of sources. Ten program managers were interviewed on twenty-two programs they manage. Given the focus of this evaluation, the review concentrated on commercial/industrial programs, though a few residential programs and several ISO programs were included as well because data were readily available and could easily be reported.

11.2 PROGRAM FEATURES AND TRENDS: FINDINGS

A number of features and feature/design trends may be observed in the programs reviewed. Some of these features and trends reflect the underlying energy resource strategies of the organizations offering the programs to customers.[1] Other features/trends are more driven by customers' perceptions of what constitutes an attractive program which they believe provides them value and satisfaction. These are briefly discussed next, along with key findings from interviews with selected program managers. Notable trends also are discussed.

Features of Interest:

1. Period applicable: Most periods are set on weekdays, though there is a mix of year-round and summer-only periods. Periods generally are defined by times when electricity resources are most costly. A significant portion of programs reflect system reliability concerns as well, however, with many having reliability that as the overriding resource objective, with cost/price-based periods being secondary.

2. Eligible participant: Most programs compiled are aimed at Large Commercial & Industrial customers, which was the focus of the compilation. Within the large C&I segment, however, program eligibility reflects the small/medium/large kW sizes commonly defined in electricity business markets, and the resulting load impacts customers can achieve.

3. Eligible load (minimum peak demand reduction amount): Ranges vary widely; most are in the 100 kW-1 MW range. A few lie outside (above and below) this range, however, on the one hand because the program is "stretching" for additional impacts (in the case of smaller eligible loads, down to as low as 25 kW for business programs), or on the other hand because of especially unique situations that address impacts available from very large industrial customers such as refineries, automobile assembly plants, large waste treatment facilities, etc.

4. Call criteria (e.g., strike price, reliability criteria, market price): There is a mix of high demand levels and high market prices used, again reflecting the underlying resource strategy. A significant number of programs cite both criteria as equally important, and other program features further define how those criteria are operated to address the resource strategy.

[1] Resource strategies primarily being either reliability-concerned or commodity price-driven, though often they are confluent.

5. Notification period (e.g., 30 minutes notice, day-ahead pricing, 2 hours): Most are "day-of" with 30-minute to 2-hour notice. The periods typically are defined relative to the alternatives in the energy/demand resource mix, and how quickly those resources can be brought to bear. Normally, shorter notification periods reflect spinning reserve values and operational requirements, while longer notification periods address spot supply market bidding and procurement opportunities as well.

6. Respondent option (e.g., mandatory if emergency, mandatory if bid, etc.): Bid-based & Real-Time Pricing (RTP) programs all are voluntary. Other programs are mostly mandatory according to contract specifications and have non-performance penalties. The penalties usually are in the form of super-prices applied to the amount of impact not achieved. They may also may take other forms, however, including simply denying the nominal discount or removing the customer from the program.

7. Duration and frequency of curtailment (e.g., paid for a minimum of 2 hours, as bid, maximum of 6 hours): There is a wide variation in duration specifics. Many programs do not have frequency or duration caps, but many others do. Some duration parameters are designed to address customers' concerns about excessive curtailment activities. These include such solutions as allowing the customer to specify their preferred duration according to a menu of options; using a tiered structure to split control and so minimize consecutive interrupt days; or creating a separate program option altogether with a differentiated price reflecting an alternative curtailment profile.

8. Compensation (e.g., minimum pricing, market price, day-ahead price with RTP adjustment for hedging by customers): Where the market has been restructured, the ISO's Locational Marginal Price is usually the basis for compensation (credits and penalties). Where the market is not restructured, utility avoided cost is the compensation basis. The nature or structure of the compensation is perhaps of more interest because of the variety of ways compensation, including penalties, may be structured. Structures include hourly discounting, addressed through commodity energy unit pricing discounts (or penalties, in cents per kWh) during peak hours and capacity demand unit pricing discounts/penalties (dollars per kW). In other compensation structures credits are returned to customers either through bill deductions or disbursed checks. These two approaches dominate the program landscape. There are alternatives, however, some programs include such creative structures as a per-event credit (not hourly), and avoiding rotating outages. A few programs' compensation structures attempt to explicitly mimic supply-side bids, hedges and settlement structures. All compensation systems are cost-based, following the underlying cost structure of the offering organization and reflecting traditional regulatory pricing policies.

9. Baseline criteria (e.g., 5 non-event days, 10 non-event days, last year's demand): "Typical Demand" is the basis for most program tariffs and contracts. Notably, however, there is a significant variation observed in how typical demand is defined. Baseline determination rules are subtle, yet have importance to both customers and their suppliers because they present opportunities to "game" the situation to the advantage of different market actors, and because the variation in how typical demand is defined require extra efforts by customers to understand the program and

participate effectively in it, while the program supplier has to address administrative complications that arise, for example in running DR programs across jurisdictional boundaries where typical demand definitions differ,[2] and so costs get driven up and staff productivity suffers. Having said this, however, most typical demands determined by multiple prior days or prior-season demand criteria that are fairly common throughout the industry.

10. Payment method: Bill credits are the most popular way to reward participants. Check disbursements and presentations are cited as a PR tool in those programs offering that venue. Aggregators generally provide their retail customers some reflection of the credits they receive from ISOs.

11. Metering: All C&I programs use interval metering. Many programs use phone line to port data. Only some programs use advanced metering, but the trend is definitely toward advanced metering as such technologies are increasingly deployed for a variety of both programmatic and other business reasons.

12. Event Notification method: Phone, pager and e-mail are widely used, with a recent influx of newer paging and internet applications making it possible to bolster communications links to better ensure the curtailment/high price message gets to customer staff responsible for executing their demand-response operations. Some programs use remote terminal units but those are considered old technology. Ironically, indications have suggested that the robust, reliable operation such units provide may not yet be matched by newer technologies. Web-based systems are popular with those who use them, but not all customer users have ready, timely access to the internet when a curtailment or high-price event is called, and so there is a risk of the customer not being able to confirm their engagement in the event.

13. Software requirements: Most programs have no specific requirements, but many have web sites that offer useful information on event likelihood and operations, tips on achieving effective load reduction, and even simple simulation software to help customers model how to best respond in events. E-mail and internet access are widely used, and increasingly for confirmation of event engagement, though with the notification risk noted above.

14. Program Fees: Most programs have none. Those who do generally apply fees to cover phone lines & metering.

Interview Findings

Program managers were asked a variety of questions regarding their experience and insights about their programs. Questions inquired of a number of different points, with the following summary findings:

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[2] For example, due to legacy situations associated with mergers, or because regulatory policy directs certain approaches.

- Program strengths and weaknesses: Strengths that promote program success include:
  - Flexibility, to fit a variety of customer situations and so gain deeper, broader program impacts
  - Having high customer "touch," to ensure program continuity and customer awareness/readiness
  - Simple participation and event criteria, for operational clarity
  - Balanced rewards and penalties, so that customers feel the value proposition is an honest one
  - Modernized communications systems and processes, to ensure effective notification, confirmation of notices sent, and to provide helpful feedback and information support to maximize impacts
  - No special fees charged to customers, to further simplify the program
  - Not too many (especially consecutive-day) events, to spread the pain of curtailments and avoid putting customers' businesses at risk
  - No customer obligation/penalty, because customers already suffer risks in participating in the program, and because loss of prospective credits (absent an explicit penalty) is often a sufficient motivator.

  Weaknesses that program managers cited include:
  - Inactivity, causing institutional memory loss and reduced program efficiency and effectiveness
  - The obverse of all the above points concerning program strengths, where programs have yet to address the concerns implicit in the conceptual and functional points discussed above.

  Ironically, high prices themselves are seen as a "strength" of programs because they get C&I customers' attention and so enable programs to succeed because there is a crisis to overcome. At the same time, high prices are a major source of dissatisfaction for customers, leaving the DR industry "between a rock and a hard place" where mitigating prices means lower program participation, yet higher prices that spur program participation also bring heightened customer concerns about maintaining their competitiveness or meeting institutional budget constraints.

- Reasons for program results over time: Like in California, across the country cyclical energy supply environments have driven program results. As noted by one program manager, "Customers won't bid at $0.10 to $0.15 per kWh, but at $0.25 to $0.35 there is a lot of participation." Where supply surpluses have been created, the economic motivation for DR programs is vastly diminished; programs are either scaled back or discontinued altogether. Importantly, however, program design was cited as a major reason for success as well, because poorly designed or operated programs do not fully exploit the market opportunities when supported by underlying price and reliability drivers. Simply put, prices alone do not drive results; there must be committed programmatic follow-through to confirm customers' good behavior, demonstrate rewards (and penalties) and maintain desired awareness, ability and behavior. Consecutive days of curtailment are a key reason for programs failing, but the issue is solvable through tiers, caps and other tactics.

- Realization rates: Most program managers these days have low expectations for program realization rates because of the current capacity surplus in different parts of the country. Thus, the relatively reduced realization rates of the last several years have been expected. There are areas and programs that have had continued significant success despite moderate supply surpluses and good reliability, however. This appears to be due to continuing program operations through testing (including mandatory "events") and marginal-price/reliability situations that are within customers' expectations of only having a few events annually (but planning on such). Program managers commented: "Only about 5 percent of signed up load actually shed." "Load reductions show about 10 percent response rates for signed up load." "At current market prices, the buyback program is getting less than 25 percent of the assigned loads." "4 to 5 MW out of what was once 400 MW, due to market prices not being high." On the other hand, where programs are tenured and active, realization rates can be high: "Quote option provided about 80 percent response by customers when last exercised."

- The role of enabling technologies: Good programs have good technical assistance (the information side of technology). This includes energy audits, even impact simulation software, rate analysis and the like. Program managers offered comments such as, "Do audits for customers to see opportunities for DR, but some [energy management] technology is a solution in search of a problem." "[We have a] database developed in-house for Interval data information service [to help customers know their load shapes and link their internal operations to the DR program]" "[Have a simulation] tool that would help a customer decide what to do if they operate in a program like this" "[Offer a] system to do rate study for customer [to compare rate alternatives and estimate bill impacts of alternative curtailment actions]"

  Event communications are absolutely technology dependent, increasingly deploying multiple-channel capabilities to better assure effective event communications. These include primarily 2-way pager-based systems but also include personal phone follow-up with customers by program sales and marketing staff, web sites and a smattering of vestigial remote-terminal systems.

  Interestingly, there is little evidence of effective integration with energy management systems that customers use fairly widely now. This may be due to technical interface incompatibilities involving data formats and communications protocols, or the basic design of energy management systems and how they operate.

- Views on program compensation: Compensation, both rewards and penalties, needs to be meaningful and equitable. They cannot be seen as a utility "scheme" to increase profits at the expense of customers' assuming the resource risk. Compensation needs to reflect industry economics, in the interviewed managers' opinion. At the customer level, curtailments need to be adequately compensated to pay for the business risks inherent in shutting down productive operations and suffering various discomforts and inconveniences. That is, customers experience real costs to participate in DR programs and events, and so the rewards need to recognize those costs, while penalties simply add to the costs customers already incur to participate.

There also is the standard set of payment issues, including timely payment, connection to performance and also the payment venue. Rewarding appropriate customer program behavior can include (and does in some programs) a public recognition of that behavior by offering checks as a tangible form of compensation, instead of the less-visible credit on the bill.

- What constitutes program success: The conventional measure of DR program success suggests that successful programs have depended more on price volatility than program design. Comparing day-ahead bidding programs, for example, shows different levels of load participation, and that this appears to be closely associated with prices being volatile (and high). Low prices and high reliability are closely associated with low DR program activity and, over time, participation. In other words, customers participate to avoid high bills and to help the community avoid outages, but they expect their energy service provider to do its share to manage costs and avoid putting too much of the energy resource mix on customers' shoulders.

  Another measure of program success, in terms of value to utilities and other energy organizations such as ISOs, is the insurance or risk management value DR programs may have for those organizations. Often (and as was found in the program manager interviews) the internal financial analysis of DR programs does not include such financial parameters, relying entirely on avoided fuel and capacity costs for defining the program value. As one program manager put it, "Program expectations are tied to prices -- when market prices were high, the program really helped; now, program expectations need to be balanced by market factors."

  A further consideration is whether the impacts are being accurately measured, since presumably more demand impact will be gained at higher prices. As well, not only accurate but *appropriate* measurement of impacts, particularly in how baselines are defined and measured, has a part to play in understanding program success. Finally, program design was cited frequently as being key to programs' success, because it affects customer satisfaction and therefore ongoing willingness to participate at high levels.

  From a customer service perspective, program success is closely related to proactive customer relationships as evidenced by annual (or more frequent) customer meetings, event notification process testing, contact updates critical to keeping customers informed and ready, and other activities to maintain customer responsiveness and readiness.

Notable Trends:

A number of trends were noted in conducting the program review. These included the following areas that pertain both to specific program design and operations, and broader strategic energy resource adequacy issues as well. To illustrate the nature of feedback gained in the program manager interviews, selected responses from interviewees have been paraphrased as noted in quotes.

1. Automation and administrative/operational improvements to increase program efficiency and effectiveness. New software applications have developed that facilitate notification and confirmation procedures, including web-based interfaces. More cost-effective and ubiquitous communications systems have been deployed that rely on increasingly robust wireless communications technologies, particularly 2-way paging and email. However, some respondents (and some customers interviewed as noted in Chapter 9) indicate that there are still problems to overcome with communications interfaces in order to assure customers get the message about curtailment events. Program managers reported a need to have redundant systems and processes because of remaining imperfections in available technology and administrative/operational systems. The trend is continuing toward more robust systems and processes, though it may be impossible to fully automate the DR process, and that may not be as important a goal as having fully effective communications with customers, particularly concerning event notice confirmation.

2. Balance of reliability and price in program design, to address both strategic needs. DR programs nationally are striving more and more to address both reliability and price concerns. Partly this is because the two issues often are intertwined, but partly it is also a question of how customers are affected by DR programs, in that they tend to view both issues similarly because they are taking the same curtailment actions under both issue regimes. Thus, customers' desire (as reported by program managers) is for a simpler, more unified program.

3. Reduced minimum impact levels to achieve greater total impacts. Most DR programs are aimed at the largest customers, as evidenced by the majority of programs having at least a 200 kW impact minimum. This achieves the greatest impact per dollar, but it may also be cost-effective to pursue smaller customers and impacts. A number of programs in fact have done so, though there is some question among program managers as to how cost-effective the program may be for some small to medium sized customer segments being pursued.

4. Rational portfolio (terms & conditions, operating criteria). In the trade-off between greater choice and simplified portfolios, programs have begun to be rationalized across portfolios by focusing on those elements that are more cost-effective and result in greater overall impacts.

5. ISO interaction in restructured states, in addition to and in conjunction with retail load-serving entities. Restructuring is driving multiple parts of the value chain to provide and promote DR programs. Just as other industries see manufacturers partnering with distributors and retailers to maximize benefits throughout the value chain, so the same phenomenon appears to be developing in electricity demand response.

6. Regular testing to maintain response capabilities and customers' attention and readiness. Programs that have survived most successfully have had relatively active customer relations, centering around communications and process testing, plus other readiness activities. These efforts appear to be increasingly on program mangers' minds, and again have been integral to successful programs' operations and customer satisfaction. "Test the program all the time. Due to inactivity, customers forget how to

run the response systems." "Annual testing is an important component of the program."

7. More timely and continuing customer service and program support. Directly related to the testing issue is the effort to keep in touch with customers as needed to address not only DR-related matters but other energy service needs that may impinge on customers' interest and ability to participate in a DR program. This includes not only energy efficiency services and customer information services but also basic service configuration and reliability. Quotes from interviews: "Worked with each individual customer to prove they were able to curtail load." "Working with the customer in advance helped create success." "Think about more customer contact during 'low' periods." "Need to educate customer about the market such that customers can be part of the solution." "Auditing assistance and capability is CRITICAL. The biggest competitor is apathy."

8. Discount/penalty consistency with supply alternatives' risk/price profiles and settlement terms. Customers intuitively believe, and more programs are addressing, the need for DR pricing to be consistent with how supply alternatives are compensated. Given that DR (or any end-use) programs have inherent differences from supply alternatives it may or may not be possible, or desirable, to ensure such consistency. But progressive managers continue to seek ways to achieve compensation equitability, if not consistency, while at the same time having to keep administrative processes simple.

9. Consideration of long-term resource needs as well as short-term spot market concerns. Some program managers have come full circle back to considering long-term resource adequacy and associated value in the DR equation, along with short-term resource needs and their valuation. Partly this is due to the nature of building and maintaining customer DR resources, which takes a long time and may have energy as well as capacity components that apply to long-term energy resource needs.[3]

10. Integrated program design to include energy efficiency programs and other services (service packaging and synergies). One strategy for capturing a greater share of the value proposition is by integrating programs and services to address different aspects of that proposition. Reliability services ensure basic service, energy efficiency services and programs help keep bills lower, and DR programs help mitigate spot prices while providing a reserve capacity resource to address short-term reliability problems. Each area addresses different issues that customers value. Several program managers identified this trend in mature program portfolios: "If you don't market demand response integrated with traditional energy efficiency you are missing an opportunity." "DR value proposition may be tough to make on its own." "Integrating EE and DR together makes customers more likely to participate." Several agreed that Supply management is always critical, with DR programs dependent on getting basic electric service and supply right to make the programs easier to sell.

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[3] Especially where DR programs are integrated with other demand-side management strategies.

11. Bridge to more competitive pricing approaches and markets. DR programs help prepare customers for further developments in electric industry restructuring and competition. Pricing concepts being introduced through DR programs provide a testing ground for how demand-elastic electricity consumers are, which is a necessary stepping stone in competitive market developments. "Customers [are] living between deregulation and capped rates -- a nuance that is being missed is that some day subsidies will go away and the customer will be shocked by what competition really means." "Managing load shapes will be important for customers eventually as competition comes." "Program gives a sneak preview of deregulated electricity markets" (even if still a long way off in Wisconsin, Missouri, other states).

11.3 LESSONS LEARNED

What clearly appears from the intelligence gathered is that the DR "industry" is in a state of flux as utilities, other load-serving entities and independent system operators continue to learn how to design programs that align energy resource strategy with customer risk/reward profiles and preferences. The industry also is continuing to learn how to operate DR programs more efficiently by utilizing technological advances in metering and control systems and improving organizational structures and practices. And, program managers have learned significant lessons that have importance for the future of DR programs.

Perhaps the most important lesson identified from the program manager interviews concerns staff commitment and continuity over the long term because of the need to cultivate customer relationships and the trust that goes with well-developed relationships. This takes time and people. As one program manager said, "You have to be patient. Customers will not just do this on their own. You need [sufficient numbers of] dedicated personnel for this to work."

Program managers pointed out a variety of under-appreciated nuances in their programs that make program justification and implementation more difficult – but also that help programs succeed. Quotes and paraphrases from the program manager interviews include the following:

- "The amount of customer outreach we do."
- "Not a lot of thought on how to evaluate program financially [relative to supply alternatives] – long-term costs/prices [vs. spot market]…good agreement is needed on financial parameters, consistent analysis"
- Internal administrative processes need to be efficient and flexible.
- Program continuity and commitment, to retain customers and hone operations capabilities, is key.
- Customer knowledge about market pricing is critical.
- Voluntary response (without penalties) is preferred and helps enrollment – but gets lower results.

Following from the interview findings and notable trends reported above, other lessons learned include:

- Simple participation and event requirements and processes, including sensible limits on event frequency and duration to avoid undue customer business consequences.

- Strive to balance program compensation: design and administer rewards and penalties in a manner that reflects customers' business risks of program participation, as well as electric system risks and costs.

- Programs that are regularly tested are more visible to customers, hone internal administrative processes and assure maximum customer response when the resource is needed.

- Price volatility and high prices get customers' attention, but alone are not sufficient to success. Good program design and operation are necessary to capitalize on the resource and keep customers satisfied.

- Do not expect high impacts (especially for bidding types of programs) during times of supply surpluses and associated low wholesale prices.

- Do expect significant customer defection even with significant credits or discounts, if penalties are perceived to be too onerous or if events are called too frequently and for too long a duration. Program credibility is strained if customers do not perceive that the utility is actively working to alleviate supply shortages or reliability problems that in the customer's mind are causing too-frequent or excessively long curtailment events.

- Technology developments have improved program productivity and bolstered program marketing and operational communications. Still, human intervention remains critical to making programs work effectively because technologies continue to have shortcomings.

- Reducing minimum impact levels is one way to achieve larger total impacts, but in doing so cost-effectiveness may be compromised to some extent.

- Integrating DR and other programs, especially energy efficiency and basic customer services, provides opportunities for cross-marketing, makes good use of common marketing and sales resources and helps rationalize and simplify product/service portfolios.

- DR program values can extend beyond short-term spot market values to include long-term resource adequacy values as well.

- Increasingly, DR programs offer a window to the competitive future of the electricity industry, and provide opportunities to explore innovative concepts used in other competitive markets but needing adaptations that reflect the unique characteristics of electricity as a commodity and energy services institutionally.

- Given the recent supply surpluses DR programs have had little activity and so there is great uncertainty about just how much impact they can provide when the supply surpluses are used up and programs will be called upon more actively.

11.4 KEYS FOR PROGRAM SUCCESS

In summary, a number of keys to program success were identified in the program review effort:

- Provide proactive customer service that reflects to customers a significant long-term organizational and staffing commitment.

- Customer choice is good, but too many options may not be as good as having a simple, rationalized portfolio with a customer-focused balance of rewards and penalties that includes reasonable limits to curtailment frequency and duration, credits and penalties that are considerate of customers' participation risks, and a few focused choices and features that have particular meaning and are clearly understandable to customers.

- Conduct regular, meaningful testing to assure customer awareness and overall program readiness.

- Strive for a thorough valuation of the resource relative to supply alternatives, including risk management value, to guide pricing and operational parameters in the program and assure equitable value with supply alternatives.

- Seek to address both reliability and price factors in programs, both to keep things simpler for customers and to broaden the program basis.

- Continue to monitor market developments and conduct small-scale experiments to test conceptual and technological innovations, because no program yet has achieved complete success and substantial room still exists to improve on historical efforts.

APPENDICES

APPENDIX A
CPP PROGRAM MATERIALS (TARIFFS, BROCHURES)

PG&E

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM

APPLICABILITY: The critical peak pricing (CPP) program is a voluntary alternative to traditional time-of-use rates. Schedule E-CPP is available to PG&E bundled-service customers with billed maximum demand of 200 kW or greater during any one of the past 12 billing (T)
months, and served on PG&E Demand Time-Of-Use (TOU) electric rate schedules A-10 (T)
TOU, E-19 (including E-19 voluntary), E-20, AG-4 (rates C and F only), AG-5 (rates C and F only) or their successors. Each customer must continue to take service under the provisions of their otherwise-applicable schedule (OAS). The CPP program only operates during the summer months (May 1 through October 31). Customers on this tariff must agree to allow the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the CPP program.

Customers may receive a transitional incentive to participate in the CPP program through December 31, 2005. Customers have the choice of receiving bill protection and/or technical incentives subject to meeting qualification criteria (see Transitional Incentive Options section below).

Customers must have an interval meter and Internet access to PG&E's Inter-Act, a web-based notification system. Customers must have the required metering and notification equipment in place prior to participation in the CPP program.

TERRITORY: This schedule is available to customers in PG&E's electric service territory.

RATES: The customer will be billed for all regular charges applicable under its otherwise-applicable rate schedule. Additional charges (based on usage on CPP operating days) and credits (based on usage on non-CPP days) will be determined according to the rates specified in this tariff. See "Definition of Time Periods" section below for specific CPP TOU period definitions. The CPP periods may differ from those of the customer's OAS. The additional energy charges applicable on CPP operating days will be determined as follows:

CPP High-Price Period Usage: The total effective energy charge for usage during the CPP High-Price Period will be five (5) times the customer's summer on-peak energy rate under their otherwise-applicable rate schedule multiplied by the actual energy usage, plus

CPP Moderate-Price Period Usage: The total effective energy charge for usage during the CPP Moderate-Price Period will be three (3) times the customer's summer part-peak energy rate under their otherwise-applicable rate schedule multiplied by the actual energy usage.

Customers taking service under Schedule E-CPP will pay reduced total effective TOU energy rates, through offsetting summer on-peak and part-peak rate credits for usage on those days that are not declared as CPP operating days, as shown in the following table. Schedule E-CPP charges and credits will only be applicable during the Summer season (May 1 to October 31), and will not affect winter season rates or bills.

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

RATES:
(Cont'd.)

Schedule E-CPP charges and credits vary according to the customer's OAS, and are as shown in the table below:

	Non-CPP Days (Credit) per kilowatt hour of usage		**CPP Days (Charge)** per kilowatt hour of usage	
	On-Peak	Part-Peak	Moderate-Price	High-Price
E-20T	$0.02856	$0.00159	$0.09511	$0.48344
E-20P	$0.03212	$0.00166	$0.10401	$0.51828
E-20S	$0.03603	$0.00372	$0.10614	$0.62424
E-19T	$0.03267	$0.00281	$0.14928	$0.57636
E-19P	$0.03305	$0.00253	$0.12425	$0.53296
E-19S	$0.03871	$0.00429	$0.12900	$0.63648
A-10T	$0.01528	$0.00689	$0.12533	$0.25650
A-10P	$0.04328	$0.00349	$0.22243	$0.72152
A-10S	$0.04948	$0.00353	$0.23041	$0.69392
AG-4C, F	$0.02328 (R)	$0.00644	$0.12884 (R)	$0.42736 (R)
AG-5C, F	$0.01882 (R)	$0.00562	$0.09521 (R)	$0.36292 (R)

Please refer to the sections of this tariff labeled "Program Operations" and "Notification and Trigger" for a complete description of how CPP Operating Days will be determined, and how customers will be notified of those days when CPP Operating Day prices will be in effect.

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

DEFINITION OF TIME PERIODS:

SUMMER (service from May 1 through October 31): (N)

CPP Operating Days (Monday through Friday, except holidays)

CPP High-Price: 3:00 p.m. to 6:00 p.m.

CPP Moderate-Price: 12:00 noon to 3:00 p.m.

Non-CPP Operating Days

Peak: As defined in the customer's otherwise-applicable rate schedule.

Partial-Peak: As defined in the customer's otherwise-applicable rate schedule.

Off-Peak: As defined in the customer's otherwise-applicable rate schedule.

WINTER (service from November 1 through April 30)

Partial-Peak: As defined in the customer's otherwise-applicable rate schedule.

Off-Peak: As defined in the customer's otherwise-applicable rate schedule.

Please refer to the sections of this tariff labeled "Program Operations" and "Notification and Trigger" for a complete description of how CPP Operating Days will be determined, and how customers will be notified of those days when CPP Operating Day prices will be in effect. (N)

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

DEFINITION OF TIME PERIODS: (Cont'd.)	HOLIDAYS: The CPP program will not operate on holidays. "Holidays" are Memorial Day, Independence Day, and Labor Day. The dates will be those on which the holidays are legally observed.	
METERING EQUIPMENT:	Each participating customer account must have an interval meter installed that can be remotely read by PG&E. Metering equipment (including telephone line, cellular, or radio communication device) must be in operation for at least ten (10) days prior to participating in the program to establish baseline. If required, as a provision for participating in the program, PG&E will provide and install the metering equipment at no cost to the customer through December 31, 2004. PG&E will also provide meter data retrieval at no cost to those customers receiving free meters through this tariff until otherwise directed by the CPUC.	(T) (T) (D)
NOTIFICATION EQUIPMENT:	Customers, at their expense, must have access to the Internet and an e-mail address to receive notification of a CPP event. In addition, all customers must have, at their expense, an alphanumeric pager that is capable of receiving a text message sent via the Internet. A customer cannot participate in the CPP program until all of these requirements have been satisfied.	
	If a CPP event occurs, customers will be notified using one or more of the above-mentioned systems. Receipt of such notice is the responsibility of the participating customer. PG&E will make best efforts to notify customers, however it is the customer's responsibility to receive such notice and to check the PG&E website to see if the Program is activated. PG&E does not guarantee the reliability of the pager system, e-mail system or Internet site by which the customer receives notification.	
CONTRACTS:	Customers must submit a signed Demand Response Program Agreement (Form 79-976) and an Customer Agreement and Password Agreement Governing Use of the Inter-Based Software (Form 79-977) in order to receive service.	(T) | (T)
	Customer's participation in this tariff will be in accordance with Electric Rule 12. Customers may terminate their E-CPP agreement by submitting a signed Cancellation of Contract and providing a minimum of 30 days' written notice. Cancellation of the agreement will become effective with the first regular billing cycle after the 30-day notice period. PG&E reserves the right to terminate the agreement upon thirty (30) days written notice.	

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

PROGRAM OPERATIONS: PG&E will notify customers by 5:00 p.m. on a day-ahead basis when a CPP operation day will occur the next business day. A CPP event will only be called Monday through Friday, excluding holidays. Notices will be issued on Friday by 5:00 p.m. for events occurring on the following Monday, or for events that are issued for Tuesday following a holiday that falls on Monday. The trigger or activation of a CPP event will be the forecasted temperatures at designated specific locations in two geographical zones. Each specific zone will operate CPP events individually, meaning that a CPP event may be triggered in one or both zones. (N)

NOTIFICATION AND TRIGGER: CPP operating days will ordinarily be determined based on day-ahead maximum temperature forecasts at specific locations within each of two designated PG&E zones. The two zones are Zone 1 (San Francisco and Peninsula) and Zone 2 (all other areas PG&E provides service).

Beginning May 1st of each summer season, the initial forecasted temperature thresholds for triggering CPP events will be:

Zone 1: 94 degrees (average of forecasts for San Francisco and San Jose)

Zone 2: 98 degrees (average of forecasts for San Francisco, San Jose, Concord, Redding, Sacramento and Fresno)

PG&E will adjust the forecasted temperature thresholds up or down, over the course of the summer as necessary, to achieve the CPP program design basis of 12 operating days each summer. For the Summer of 2003, the maximum number of critical peak days will be prorated to account for the late starting date. At the beginning of each calendar month, PG&E will review the number of CPP operating days that have already occurred and may adjust the applicable temperature threshold for each zone up or down (increments of 2 degrees), in accordance with historical weather patterns. Customers will be notified of the applicable temperature threshold for their zone via the Inter-Act system.

CPP events may also be initiated as warranted by extreme system conditions such as special alerts issued by the California Independent System Operator, or under conditions of high forecasted California spot market power prices or for testing/evaluation purposes. (N)

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

PROGRAM RESEARCH AND ANALYSIS:	Customers receiving service under this tariff must agree to allow personnel from the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the CPP program. Customer must submit a signed Authorization To Receive Customer Information or Act On A Customer's Behalf form giving the CEC authorization to request billing history and meter usage data information.
PROGRAM TERM:	The CPP program will remain open until terminated or superceded by action of the CPUC.
BILLLING:	Monthly bills are calculated in accordance with the customer's OAS and the rates contained herein. The difference between the amount due under the customer's OAS and the amount due under critical-peak pricing will appear on the customer's bill as an additional charge or credit.
CUSTOMER MULTIPLE-METER PREMISES:	A customer with multiple accounts on a single site (e.g., contiguous property, campus facilities, business parks) may participate in the CPP program with accounts on the premises that are less than 200 kW (as described in the Applicability Section) provided at least one of the customer accounts has a billed maximum demand of 200 kW or greater during any one of the past 12 biling months and is participating in the CPP program. The customer's taxpayer identification number must be the same for each account participating in the CPP program under this provision and each account must be listed on the Demand Response Program Agreement. All other CPP program requirements must be met for each participating account. The bill for each account will be calculated on a stand-alone basis.
TRANSITIONAL INCENTIVE OPTIONS:	Customers in the CPP program may elect either or both of two types of optional transitional incentives: (1) 100 percent bill protection; and (2) professional technical assistance. Bill protection is capped at a maximum systemwide participation level of 200 MWs of load drop. Funding for professional technical assistance incentives is capped at a maximum budget as established by the CPUC and is available on a first-come, first-served basis, subject to meeting qualification criteria. No transitional incentives will be paid beyond December 31, 2005, or after incentive funds are depleted, whichever is earlier. CPP customers receiving a transitional incentive in the Demand Bidding Program (DBP) are not eligible to receive transitional incentives for professional technical assistance in the CPP program.

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

TRANSITIONAL INCENTIVE OPTIONS: (Cont'd.)

A. Bill Protection: A customer electing the bill protection option will not pay more under the CPP program than it would pay under its otherwise-applicable rate schedule for the 14-month bill protection period provided the customer: (1) remains in the CPP program for the entire duration of the rate protection period; and (2) maintains an open account. Bill protection benefits will be computed on a cumulative basis at the end of the bill protection period. (D)

(D)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

TRANSITIONAL INCENTIVE OPTIONS: (Cont'd.)

B. Technical Assistance Incentive: The technical assistance option shall enable the customers to earn a rebate for professional technical assistance that enhances the customer's ability to respond to curtailment requests for on-peak demand reductions. A customer requesting this incentive may receive a rebate (not to exceed costs) based on $50 per kW of curtailable on-peak load reduction nominated by the customer through a signed Technical Assistance incentive Application (Form 79-1005). Curtailable on-peak load shall be defined as existing load that is temporarily reduced or shifted to another time period as a result of an E-CPP Event being issued. The customer shall receive an incentive payment equal to 50 percent of the rebate following submission of a signed Application prepared in conjunction with an audit conducted by a CEC-certified Professional Engineer (P.E.) of potential on-peak load reductions. The remaining 50 percent of the rebate shall be paid after the customer has demonstrated actual peak demand reductions equal to at least 50 percent of their load drop per CPP event as averaged over four consecutive CPP months. The demand (energy) reduction will be determined by the same methodology as defined in the Bill Protection section of this schedule. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate. The technical assistance incentives will be available to participants until December 31, 2005, or until the funding for the transitional incentives are exhausted. Participants receiving a technical assistance incentive under the Demand Bidding Program (Schedule E-DBP) are ineligible to receive technical assistance incentive for the same consulting study under this schedule. (N)

(Continued)

SCHEDULE E-CPP—CRITICAL PEAK PRICING PROGRAM
(Continued)

INTERACTION WITH OTHER DEMAND REDUCTION PROGRAMS: Participants in the CPP program may also participate in the Demand Bidding Program (Schedule E-DBP) and the California Power Authority Demand Reserves Partnership Program (CPA DRP) but shall not receive energy payment for performance under those programs during CPP event hours. Customers who participate in a California Power Authority (CPA) or a third-party sponsored interruptible load program must immediately notify PG&E of such activity. CPP participants shall not participate in the Non-Firm Program, Base Interruptible Program (Schedule E-BIP), the Optional Binding Mandatory Curtailment Program (Schedule E-OBMC), the Pilot Optional Binding Mandatory Curtailment Program (Schedule E-POBMC), or the Scheduled Load Reduction Program (Schedule E-SLRP) while on the CPP program. (N)

SCE

Schedule GS2-TOU-CPP — Sheet 1

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING

APPLICABILITY

This Schedule is optional for Bundled Service Customers currently served under Schedule TOU-GS-2 or GS-2 with the Time-of-Use Pricing Option, with maximum demands above 200 kW, defined herein as registered Maximum Demand of greater than 200 kW in any three months during the preceding twelve months, but not exceeding 500 kW. A customer served under this Schedule whose monthly Maximum Demand, in the opinion of the SCE, is expected to exceed 500 kW or has exceeded 500 kW in any three months during the preceding 12 months is ineligible for service under this Schedule and shall be transferred to Schedule TOU-8-CPP. Further, any customer served under this Schedule whose monthly Maximum Demand has registered less than 200 kW for twelve consecutive months is also ineligible for service under this Schedule and shall be transferred to an applicable rate schedule. Customer service accounts served under Schedule S are not eligible for service under this Schedule. A customer's participation in other demand response programs may affect a customer's eligibility for service under this Schedule, or the level of credits available under such other programs (see Special Conditions section). Service under this Schedule requires the installation of interval metering equipment, as defined in this Schedule's Special Conditions section, prior to participation under this Schedule and is subject to the availability of such metering.

TERRITORY

Within the entire territory served.

RATES

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG	DWR
Energy Charge- $/kWh/Meter/Month									
CPP Event									
Summer Season									
CPP Moderate Price Period									
Noon – 3:00 p.m.	0.00016	0.00954 (I)	0.00056	0.00321	0.00012	0.00493	0.01897 (I)	0.36590	0.09056 (I)
CPP High-Price Period									
3:00 p.m. – 6:00 p.m.	0.00016	0.00954 (I)	0.00056	0.00321	0.00012	0.00493	0.01897 (I)	0.95686	0.09056 (I)
Non CPP Event Time Periods									
Summer Season – On Peak	0.00016	0.00954 (I)	0.00056	0.00321	0.00012	0.00493	0.01897 (I)	0.10464 (R)	0.09056 (I)
Mid Peak	0.00016	0.00954 (I)	0.00056	0.00321	0.00012	0.00493	0.01897 (I)	0.05814 (R)	0.09056 (I)
Off-Peak	0.00016	0.00954 (I)	0.00056	0.00321	0.00012	0.00493	0.01897 (I)	0.05336 (R)	0.09056 (I)
Winter Season – Mid-Peak	0.00016	0.00954 (I)	0.00056	0.00321	0.00012	0.00493	0.01897 (I)	0.06487 (R)	0.09056 (I)
Off-Peak	0.00016	0.00954 (I)	0.00056	0.00321	0.00012	0.00493	0.01897 (I)	0.05336 (R)	0.09056 (I)
Customer Charge - $/Meter/Month	0.00	67.78 (I)					67.78 (I)	6.25 (R)	
Demand Charge - $/kW of Billing Demand/Meter/Month									
Facilities Related	1.09	4.35 (I)					5.44 (I)	0.77 (R)	
Time Related									
Summer	0.00	7.04 (I)					7.04 (I)	1.87 (R)	
Winter	0.00	0.00					0.00	0.00	
Single Phase Service - $/Month	0.00	(2.40)					(2.40)	0.00	

(Continued)

Schedule GS2-TOU-CPP Sheet 2

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

RATES (Continued)

	Delivery Service							Gen[8]	
	Trans[1]	Distrbtn[2]	NDC[3]	PPPC[4]	PUCRF[5]	DWRBC[6]	Total[7]	URG	DWR
Excess Transformer Capacity - $/kVA/month	0.00	1.00					1.00	0.00	
Voltage Discount, Demand - %									
From 2 kV to 50 kV		100.00					100.00*		
Above 50 kV		100.00					100.00*		
Voltage Discount, Energy - %									
From 2 kV to 50 kV	0.00	20.00					20.00*	80.00*	
Above 50 kV	0.00	20.00					20.00*	80.00*	
Power Factor Adjustment - $/kVA									
Greater than 50 kV	0.00	0.18					0.18	0.00	
50 kV or less	0.00	0.23					0.23	0.00	
California Alternate Rates for Energy Discount - %							100.00*		

* Represents 100% of the discount percentage as shown in the applicable Special Condition of this Schedule.
1 Trans = Transmission and the Transmission Owners Tariff Charge Adjustments (TOTCA) which are FERC approved. The TOTCA represents the Transmission Revenue Balancing Account Adjustment (TRBAA) of negative $0.00047 per kWh, Reliability Services Balancing Account Adjustment (RSBAA) of $0.00022 per kWh, and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.00041 per kWh.
2 Distrbtn = Distribution
3 NDC = Nuclear Decommissioning Charge
4 PPPC = Public Purpose Programs Charge
5 PUCRF = The PUC Reimbursement Fee is described in Schedule RF-E.
6 DWRBC = Department of Water Resources (DWR) Bond Charge. The DWR Bond Charge is not applicable to exempt Bundled Service and Direct Access Customers, as defined in and pursuant to D.02-10-063, D.02-02-051, and D.02-12-082.
7 Total = Total Delivery Service rates that are applicable to both Bundled Service and Direct Access (DA) Customers, except DA Customers are not subject to the DWRBC rate component of this Schedule but instead pay the DWRBC as provided by Schedule DA.
8 Gen = Generation – The Gen rates are applicable only to Bundled Service Customers. When calculating the Energy Charge, the Gen portion is calculated as described in the Billing Calculation Special Condition of this Schedule.

(Continued)

Schedule GS2-TOU-CPP Sheet 3
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS

1. Time periods are defined as follows:

CPP Moderate–Price Period: Noon to 3:00 p.m. during a CPP Event only

CPP High-Price Period: 3:00 p.m. to 6:00 p.m. during a CPP Event only

On-Peak: Noon to 6:00 p.m. summer weekdays except CPP Moderate-Price Periods, CPP High-Price Periods, and holidays
Mid-Peak: 8:00 a.m. to Noon and 6:00 p.m. to 11:00 p.m. summer weekdays except holidays
8:00 a.m. to 9:00 p.m. winter weekdays except holidays
Off-Peak: All other hours.

Holidays are New Year's Day (January 1), Washington's Birthday (third Monday in February), Memorial Day (last Monday in May), Independence Day (July 4), Labor Day (first Monday in September), Veterans Day (November 11), Thanksgiving Day (fourth Thursday in November), and Christmas (December 25).

When any holiday listed above falls on Sunday, the following Monday will be recognized as an off-peak period. No change will be made for holidays falling on Saturday.

The summer season shall commence at 12:00 a.m. on the first Sunday in June and continue until 12:00 a.m. of the first Sunday in October of each year. The winter season shall commence at 12:00 a.m. on the first Sunday in October of each year and continue until 12:00 a.m. of the first Sunday in June of the following year.

2. CPP Events: SCE may, at its discretion, invoke a CPP Event during the summer season time period of Noon to 6:00 p.m., when SCE determines any of the following conditions exist: there is high system peak demand and/or low generation reserves; system constraints; high wholesale market prices; a Los Angeles Civic Center temperature of 87 degrees or above by 2 p.m. two days prior to a CPP Event; special alerts issued by California Independent System Operator (CAISO); and/or for testing/evaluation purposes. SCE will adjust the temperature threshold up or down, over the course of the summer season as necessary, to achieve the CPP program design basis of 12 CPP Events per summer season. (C)

a. SCE reserves the right to cancel a CPP Event up to one day prior to the start of such event. (N)

b. Unless modified or extended by the Commission on or before June 14, 2005, the forecasted Los Angeles Civic Center temperature of 87 degrees or above by 2 p.m. two days prior to a CPP Event, shall revert back to one day prior to a CPP Event, effective June 15, 2005. (N)

3. Number of CPP Events: CPP Events will be invoked by SCE during the summer season and shall be limited to 12 CPP Events. However, for the summer season of 2003, the maximum number of CPP Events will be prorated to account for the late starting date of this program.

4. Notification of a CPP Event: SCE will notify customers of a CPP Event via SCE's notification system. SCE's primary notification method will be via telephone call, but the customer may also elect to receive notification via pager, electronic mail, cellular telephone, or by fax as a courtesy. SCE will begin to notify customers by 3:00 p.m. at least two days before a CPP Event. If SCE cannot contact the customer on the first attempt, at least two more attempts will be made. However, SCE does not guarantee customer receipt of the notification. Customers will be responsible for all charges incurred during a CPP Event, even if actual notice is not received. (T)

a. Unless modified or extended by the Commission on or before June 14, 2005, the Notification of a CPP Event shall revert back to such notification beginning by 3:00 p.m. the day before a CPP Event, effective June 15, 2005. (N)
(N)

(Continued)

Schedule GS2-TOU-CPP Sheet 4
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

5. Participation in other Programs: Customers served under this Schedule may also participate in SCE's Demand Bidding Program (DBP) or the California Power Authority Demand Reserves Partnership Program (CPA DRP), but will be ineligible for any energy credits under these programs during a CPP Event.

6. Required Metering and Notification Equipment: Prior to participation on this Schedule, a customer must have Interval Metering and a designated primary phone line capable of receiving CPP Event notifications. Metering equipment must be in operation for at least ten (10) days prior to participation on this Schedule to establish a customer's Customer Specific Energy Baseline (CSEB). For participating service accounts without the required interval metering SCE will provide and install such equipment at no cost to the customer through December 31, 2004.

7. Transitional Incentive Options: Two Transitional Incentive Options, Bill Protection and Technical Assistance, are available to customers served under this Schedule. Both Transitional Incentive Options will continue until December 31, 2005, or until funding is exhausted. Customers who do not, or can not, participate in the Bill Protection Option will be subject to the charges under this Schedule at all times. Customers who meet all of the conditions outlined below may participate in one or both of the following Transitional Incentive Options:

   a. Bill Protection Option:
      (1) A participating customer may receive a Bill Protection credit for the difference in total charges, when such charges, as calculated under this Schedule, exceed total charges as calculated under the customer's Otherwise Applicable Tariff (OAT), as measured over a period of 14 months from the date the customer elects this option (Commitment Period). For purposes of this Special Condition, a customer's OAT shall be defined as the rate schedule from which the customer transferred from, prior to participation on this rate schedule;

      (2) This option will be closed to new customers on all CPP Schedules once SCE determines that 200 MWs of potential load reduction is participating on the Bill Protection Option. Additionally, no new customers may start their participation on this option after October 31, 2004;

      (3) If a participating customer is either voluntarily or involuntarily removed from this Schedule prior to completion of the Commitment Period, such customer shall not receive a Bill Protection credit for the period such customer was served under this Schedule;

      (4) At the end of the Commitment Period one of the following will occur: (T)

         (a) If a participating customer's bill, as calculated under this Schedule over the entire Commitment Period is greater than their bill as calculated under their OAT over the entire Commitment Period, then such customer will receive a Bill Protection Credit equal to CPP charges minus OAT charges. (T)
         (b) If a participating customer's bill, as calculated under this Schedule over the entire Commitment Period is equal to or less than their bill as calculated under their OAT over the entire Commitment Period, then such customer will not receive a Bill Protection Credit. (T)

(D)

(Continued)

Schedule GS2-TOU-CPP Sheet 5
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

7. Transitional Incentive Options: (Continued)

a. Bill Protection Option: (Continued)

(D)

(5) Bill Protection benefits are computed on a cumulative basis at the end of the customer's Commitment Period and, if applicable, a Bill Protection credit shall appear on the customer's bill following the end of the Commitment Period. (T)

b. Technical Assistance Option:

(1) The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances a customer's ability to respond to curtailment requests for on-peak demand reductions. A customer requesting this incentive may receive a rebate (not to exceed costs) based on $50 per kW of curtailable on-peak load reduction nominated by the customer through a signed Technical Assistance Incentive Application (Form 14-752). Curtailable on-peak load shall be defined as existing load that is temporarily reduced or shifted to another time period as a result of an CPP Event being issued.

(2) The customer shall receive an incentive payment equal to 50 percent of the rebate following submission of a signed Application (Form 14-752) prepared in conjunction with an audit conducted by a CEC-certified Professional Engineer (P.E) of potential on-peak load reduction.

(3) The remaining 50 percent of the rebate shall be paid after the customer has demonstrated actual peak demand reductions equal to at least 50 percent of their nominated load drop per CPP Event, as averaged over four consecutive CPP months.

(4) The demand (energy) reduction will be determined by the same methodology as defined in the Bill Protection section of this schedule. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate.

(5) Participants receiving a technical assistance incentive under the Demand Bidding Program (DBP) are ineligible to receive a technical assistance incentive for the same consulting study under this schedule.

(Continued)

Schedule GS2-TOU-CPP Sheet 6 (T)

GENERAL SERVICE-TIME-OF-USE-DEMAND METERED

CRITICAL PEAK PRICING

(Continued)

SPECIAL CONDITIONS (Continued)

8. Customer Site Visits: All customers served under this Schedule agree to allow the California Energy Commission, or its contracted agents, to conduct site visits for measurement and evaluation, and further agree to complete all program evaluation surveys. Upon request, the customer shall be required to authorize the release of their information to the CEC, or it's agent, for evaluation purposes.

9. Associated Service Accounts: Customers served under this Schedule with otherwise eligible service accounts located on the same or immediately adjacent Premises as the service account currently receiving service under this Schedule may choose to have one or all of such service accounts served under an applicable CPP schedule without meeting the Maximum Demand requirements, as long as at least one account remains above 200 kW at all times and such service account receives service under an applicable CPP schedule.

10. Voltage: Service will be supplied at one standard voltage.

11. Maximum Demand: The maximum demand shall be established for each monthly billing period. Maximum demand shall be measured by taking the maximum average kilowatt input indicated or recorded by instruments, during any 15-minute metered interval, but, where applicable, not less than the diversified resistance welder load computed in accordance with the section designated Welder Service in Rule 2. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.

12. Billing Demand: The Billing Demand shall be the kilowatts of Maximum Demand, determined to the nearest kW. The Demand Charge shall include the following billing components. The Time Related Component shall be for the kilowatts of Maximum Demand recorded during (or established for) the monthly billing period. The Facilities Related Component shall be for the greater of the kilowatts of Maximum Demand recorded during (or established for) the monthly billing period or 50% of the highest Maximum Demand established in the preceding eleven months (Ratcheted Demand). However, when SCE determines the customer's meter will record little or no energy use for extended periods of time or when the customer's meter has not recorded a Maximum Demand in the preceding eleven months, the Facilities Related Component of the Demand Charge may be established at 50 percent of the customer's connected load.

13. Single-Phase Service: Where SCE provides single-phase service, the billing will be reduced by the amount shown in the Rates section, above. (T)

14. Excess Transformer Capacity: Excess Transformer Capacity is the amount of transformer capacity requested by a customer, or required by the SCE, in excess of that which the SCE would normally install to serve the customer's Maximum Demand. Excess Transformer Capacity shall be billed at the amount shown in the Rates section, above. (T)

15. Voltage Discount: The monthly Facilities Related Demand Charge will be reduced by 23.3% for service delivered and metered at voltages of 2 kV through 50 kV and by 71.1% for service delivered and metered at voltages over 50 kV. The discount applied to Energy Charges is calculated by taking the Base Rate Energy Charge in effect on June 10, 1996 of $0.02307 per kWh and multiplying by 3.2% for service delivered and metered at voltages of 2 kV through 50 kV, and by 14.8% for service delivered and metered at voltages over 50 kV.

(Continued)

Schedule GS2-TOU-CPP Sheet 7 (T)
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

16. Power Factor Adjustment. When the Maximum Demand has exceeded 200 kW for three consecutive months, kilovar metering will be installed as soon as practical, and, thereafter, until the Maximum Demand has been less than 150 kW for twelve consecutive months, the billing will be increased each month for power factor by the amount shown in the Rates section above for service metered and delivered at the applicable voltage level, based on the per kilovar of maximum Reactive Demand imposed on SCE. The reactive demand will be determined as follows:

    a. Service metered and delivered at voltages of 4 kV or greater and for all Cogeneration and Small Power Production customers:

       The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering during any 15-minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

    b. Service metered and delivered at voltages Less than 4 kV:

       (1) For customers with metering used for billing that measures reactive demand.

           The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering during any 15-minute metered interval in the month. The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

       (2) For customers with metering used for billing that measures kilovar-hours instead of reactive demand.

           The kilovars of reactive demand shall be calculated by multiplying the kilowatts of measured maximum demand by the ratio of the kilovar-hours to the kilowatthours. Demands in kilowatts and kilovars shall be determined to the nearest unit. A ratchet device will be installed on the kilovar-hour meter to prevent its reverse operation on leading power factors.

17. Temporary Discontinuance of Service: When the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within twelve months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

(Continued)

Schedule GS2-TOU-CPP Sheet 8 (T)
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

18. Customer-Owned Electrical Generating Facilities:

a. Where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A generation interconnection agreement is required for such operation. (T) (T)

b. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

19. CARE Discount: Customers who meet the definition of a group living facility as defined in the Preliminary Statement, Part O, Section 3.f., may qualify for a 20% discount off of their bill prior to application of the PUC Reimbursement Fee and any applicable user fees, taxes, and late payment charges. Customers eligible for the CARE Discount will not be required to pay the CARE Surcharge. as set forth in Preliminary Statement, Part O, Section 5 and are not subject to the DWRBC rate component of the Total charges for Delivery Service. An Application and Eligibility Declaration (Form No. 14-526), as defined in the Preliminary Statement, Part O, Section 3.h., is required for service under this Special Condition. Eligible customers shall be billed on this Schedule commencing no later than one billing period after receipt and approval of the customer's application by SCE. Customers may be rebilled on the applicable rate schedule for periods in which they do not meet the eligibility requirements for the CARE discount as defined in the Preliminary Statement, Part O, Section 3.g. and Section 3.i.

20. Billing Calculation: A customer’s bill is first calculated according to the total rates and conditions above. The following adjustments are made depending on the option applicable to the customer. (N)

Except for the Energy Charge, the charges listed in the Rates section are calculated by multiplying the Total Delivery Service rates and the Generation rates, when applicable, by the billing determinants (e.g., per kilowatt [kW], kilowatthour [kWh], kilovar [kVa] etc.),

The Energy Charge, however, is determined by multiplying the total kWhs by the Total Delivery Service per kWh rates to calculate the Delivery Service amount of the Charge. To calculate the Generation amount, SCE determines what portion of the total kWhs is supplied by the Utility Retained Generation (URG) and the Department of Water Resources (DWR). The kWhs supplied by the URG are multiplied by the URG per kWh rates and the kWhs supplied by the DWR are multiplied by the DWR per kWh rate and the two products are summed to arrive at the Generation amount. The Energy Charge is the sum of the Delivery Service amount and the Generation amount.

For each billing period, SCE determines the portion of total kWhs supplied by SCE’s URG and by the DWR. This determination is made by averaging the daily percentages of energy supplied to SCE’s Bundled Service Customers by SCE’s URG and by the DWR.

Bundled Service Customers receive Delivery Service from SCE and receive supply (Gen) service from both SCE’s URG and the DWR. The customer’s bill is the sum of the charges for Delivery Service and Gen determined, as described in this Special Condition, and subject to applicable discounts or adjustments provided under SCE’s tariff schedules. (N)
(D)

(Continued)

Schedule GS2-TOU-CPP Sheet 9 (T)
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

21. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages.

Sub-transmission customers, except for those customers exempt from rotating outages, are to be included in controlled, rotating outages when required by the Independent System Operator (ISO). To the extent feasible, SCE will coordinate rotating outages applicable to Sub-transmission customers who are fossil fuel producers and pipeline operators and users to minimize disruption to public health and safety. SCE shall not include a Sub-transmission customer in an applicable rotating outage group if the customer's inclusion would jeopardize electric system integrity. Sub-transmission customers who are not exempt from rotating outages, and seek such exemption, may submit an Optional Binding Mandatory Curtailment (OBMC) Plan to SCE in accordance with Schedule OBMC. If SCE approves a customer's OBMC Plan, the customer will become exempt from rotating outages and will be subject to the terms and conditions of Schedule OBMC and its associated contract.

Non-exempt Sub-transmission customers shall be required to drop their entire electrical load during applicable rotating outages by either (1) implementing the load reduction on their own initiative, in accordance with subsection a, below; or (2) having SCE implement the load reduction through remote-controlled load drop equipment (control equipment) in accordance with subsection b, below. A Sub-transmission customer shall normally be subject to the provisions of subsection a. If SCE approves a customer's request to have SCE implement the load reduction or if the customer does not did not comply with prior required load reductions, as specified in subsection c, the customer will be subject to the provisions of subsection b.

a. Customer-Implemented Load Reduction.

(i) Notification of Required Load Reduction. At the direction of the ISO, SCE shall notify each Sub-transmission customers in an affected rotating outage group to drop its entire load. Within 30 minutes of such notification, the customer must drop its entire load. The customer shall not return the dropped load to service until 90 minutes after SCE sent the notification to the customer to drop its load, unless SCE notifies the customer that it may return its load to service prior to the expiration of the 90 minutes.

(ii) Method of Notification. SCE will notify Sub-transmission customers who are required to implement their own load reduction via telephone, by either an automated calling system or a manual call to a business telephone number or cellular phone number designated by the customer. The designated telephone number will be used for the sole purpose of receiving SCE's rotating outage notification and must be available to receive the notification at all times. When SCE sends the notification to the designated telephone number the customer is responsible for dropping its entire load in accordance with subsection a. (i)., above. The customer is responsible for informing SCE, in writing, of the telephone number and contact name for purposes of receiving the notification of a rotating outage.

(Continued)

SPECIAL CONDITIONS (Continued)

21. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

a. Customer-Implemented Load Reduction. (Continued)

(iii) Excess Energy Charges. If a Sub-transmission customer fails to drop its entire load within 30 minutes of notification by SCE, and/or fails to maintain the entire load drop until 90 minutes after the time notification was sent to the customer, unless SCE otherwise notified the customer that it may return its load to service earlier in accordance with subsection a. (i) above, SCE shall assess Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during the applicable rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage penalty period in hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Sub-transmission customer's regularly scheduled meter read date following the applicable rotating outage.

For customers with net-generators, Excess Energy Charges shall not apply during periods of verifiable scheduled generator maintenance or if the customer's generator suffers a verified forced outage. The scheduled maintenance must be approved in advance by both the ISO and SCE, but approval may not be unreasonably held.

(iv) Authorized Residual Ancillary Load. Authorized Residual Ancillary Load is load that is deemed to be equivalent to five percent of the Sub-transmission customer's prior billing month's recorded Maximum Demand. This minimum load level is used as a proxy to allow for no-load transformer losses and load attributed to minimum grid parallel operation for generators connected under Rule 21.

b. SCE-Implemented Load Reduction.

Non-exempt Sub-transmission customers may request, in writing, to have SCE drop the customer's entire load during all applicable rotating outages using SCE's remote-controlled load drop equipment (control equipment). If SCE agrees to such arrangement, SCE will implement the load drop by using one of the following methods:

(i) Control Equipment Installed. For a Sub-transmission customer whose load can be dropped by SCE's existing control equipment, SCE will implement the load drop during a rotating outage applicable to the customer. The customer will not be subject to the Notification and or Excess Energy Charge provisions set forth in subsection a, above.

(Continued)

Schedule GS2-TOU-CPP Sheet 11 (T)
GENERAL SERVICE-TIME-OF-USE-DEMAND METERED
CRITICAL PEAK PRICING
(Continued)

SPECIAL CONDITIONS (Continued)

21. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

b. SCE-Implemented Load Reduction. (Continued)

(ii) Control Equipment Pending Installation. For a Sub-transmission customer whose load can not be dropped by SCE's existing control equipment, the customer must request the installation of such equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities. Pending the installation of the control equipment, the customer will be responsible for dropping load in accordance with the provisions of subsection a, above, including subject the Notification and Excess Energy Charge provisions.

c. Non-compliance: A non-exempt Sub-transmission customer subject to subsection a, above, who fails to drop load during three rotating outages in a three year period to a level of at least 20% of the customer's prior billing month's recorded Maximum Demand averaged over the applicable rotating outage period, is not in compliance with this tariff. The three year period shall commence with the first failure to drop load as specified in this subsection. A customer not in compliance with this condition will be placed at the top of the Sub-transmission customer rotating outage group list and will be expected to comply with subsequent applicable rotating outages. In addition, the customer must select one of the two options below within fifteen days after receiving written notice of non-compliance from SCE. A customer failing to make a selection within the specified time frame will be subject to subsection c. (ii) below.

(i) Subject to Schedule OBMC: The customer shall submit an OBMC Plan, in accordance with Schedule OBMC, within 30 calendar days of receiving written notice of non-compliance from SCE. Pending the submittal of the OBMC Plan by the customer and pending the review and acceptance of the OBMC Plan by SCE, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy charge provisions. If the customer fails to submit an OBMC Plan within 30 days of receiving notice of non-compliance from SCE, or if the customer's OBMC Plan is not approved by SCE, or if the customer fails to meet the requirements of Schedule OBMC once the OBMC Plan is approved, the customer shall be subject subsection c. (ii), below.

(ii) Installation of Control Equipment. The customer shall be subject to the installation of control equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

CRITICAL PEAK PRICING RATE OPTION
QUESTIONS AND ANSWERS

PROGRAM OVERVIEW

Southern California Edison's (SCE) Critical Peak Pricing (CPP) program may benefit customers, who have at least one account with registered demands greater than 200 kilowatts (kW), and can reduce, or shift, their power out of the summer season noon to 6:00 p.m. period during a CPP Event. Energy rates during summer season CPP Events are approximately three to five times higher than energy rates during summer season non-CPP Events. However, customers on a CPP schedule receive reduced energy rates for all non-CPP usage during the summer on-peak and year-round mid-peak periods.

BENEFITS TO YOU

What are the benefits of participating in the CPP?

There are several benefits to taking part in the CPP:

1) Reduced summertime on-peak energy rates and reduced year-round mid-peak energy rates.
2) Bill Protection Incentive – an option that provides assurance that participants will not be charged energy rates higher than the energy rates from the rate schedule they transferred from prior to joining the CPP program, up to the first 14 months on the Program upon meeting certain minimum performance standards.
3) Technical Assistance Incentive – an option that provides a cash rebate for professional technical assistance that enhances your ability to reduce power during CPP Events. This option is not available to customers who are currently participating in the Demand Bidding Program (DBP) and have already signed up for the Technical Assistance Incentive under the DBP Program.

ELIGIBILITY

Am I eligible for the CPP program?

SCE's CPP Program will be available to most customers with demands greater than 200 kW and who rely on SCE for generation, transmission and distribution of electric services (bundled service customers). Interval metering is required prior to participation and Direct Access customers are not eligible for service on any of SCE's CPP rate schedules.

I have more than one meter, can I still participate on the CPP program?

Under certain circumstances, if additional meters are located at one customer site, one or all of the customer's meters may also be served under a CPP Rate.

PROGRAM REQUIREMENTS

Are there any program requirements for participating on the CPP?

Yes. In addition to meeting the eligibility requirements for the program as detailed in the tariffs, as a participant in the CPP, you must agree to allow the California Energy Commission, or its contracted agent, to complete any surveys for measurement and evaluations, as needed to enhance the program, as well as completing all program surveys.

How long does a customer have to stay on the CPP Program?

Customers must remain on the CPP rate for a minimum of 12 months. After participating in the CPP for 12 months, customers can opt-off at anytime. If a customer is participating in the Bill Protection Incentive, there is a requirement to stay on the CPP Program for 14-months to receive the benefits of the Bill Protection Incentive.

MULTIPLE PROGRAMS PARTICIPATION

Can I participate in other Demand Response Programs while on the CPP rate?

Yes. There are other Demand Response Programs you can participate while on the CPP rate - SCE's Scheduled Load Reduction Program (SLRP), Demand Bidding Program (DBP) and the California Power Authority Demand Reserve Program (CPA DRP), as applicable. Customers will be ineligible to receive credit on SLRP, DBP, or the CPA DRP during a CPP event.

Can I be on SCE's interruptible programs and the CPP at the same time?

No. CPP customers may not participate in interruptible programs such as Large Power Interruptible Programs (*i.e.*, I-6, I-6-BIP) or Air Conditioner Cycling Program.

CRITICAL PEAK EVENTS

When and how often will the CPP be activated?

A CPP Event can only be activated during SCE's summer season between Noon and 6:00 p.m., Monday through Friday, excluding holidays. There are a maximum of twelve (12) CPP events per summer season.

When is SCE's summer season?

The summer season begins at 12:00 a.m. the first Sunday in June and continues until 12:00 a.m. the first Sunday in October of each year.

How is a CPP event activated?

SCE will notify participants when a CPP Event is necessary. There are a number of "triggers" that may activate a CPP Event, including high system demand and/or low generation supply, system emergency testing, high market prices, Los Angeles Civic Center temperature registering 87 degrees or higher by 2:00 p.m.,— or at SCE's discretion. SCE may adjust the temperature threshold up or down, over the course of the summer season as necessary, to achieve the targeted program event maximum of twelve (12) CPP events per summer season.

EVENT NOTIFICATION

When will I be notified of a CPP event?

SCE will attempt to notify you the day before a CPP event of the opportunity to reduce or eliminate on-peak power usage (between Noon and 6:00 p.m.). SCE will make three attempts to notify you via your designated primary telephone number: First attempt at 3:00 p.m.; second attempt, if necessary, at 4:00 p.m.; and final attempt, if necessary, at 5:00 p.m. SCE does not guarantee actual receipt of notification.

Are there other ways to receive notification of a CPP event?

Yes. You may opt to receive a courtesy notification. In addition to the notification via your designated primary telephone number, notification via pager, cellular telephone, e-mail or fax can be arranged. All equipment needed to receive notification will be at your expense.

What do I do when I am notified of a CPP event?

The choice on how to respond to a CPP event is yours, however, if you choose not to reduce your electricity usage during a CPP event, between the peak times of Noon to 6:00 p.m. you will be charged a higher per kilowatt-hour (kWh) price for power used. Participating customers will be responsible for all charges incurred during a CPP Event, even if the customer does not receive actual notice.

Critical Peak Pricing Peak Periods	
Noon to 3:00 p.m.	***3 times*** the standard rate schedule, mid-peak energy charge
3:00 p.m. to 6:00 p.m.	***5 times*** the standard rate schedule, on-peak energy charge

EQUIPMENT

Do I need special equipment?

Yes. Prior to participation in the CPP program, you must have an interval meter. If you do not already have an interval meter, SCE will provide one for you at no charge. Internet access to the CPP Website is not required, but suggested.

REPORTS

Can I view my power usage?

Yes. CPP customers may take advantage of SCE's Cost Manager^{sm} (an application within the SCE EnergyManager^{sm} website). You will be given a "User ID" and "Password" so you can log onto www.sceenergymanager.com and click on "User Reports" allowing you to view potential power reduction. If you have any questions regarding the website, you can send an e-mail to DRP@SCE.COM.

What reports are available to CPP customers?

CPP participants will have access to: 1) Previous 7 Day Energy Usage Report, 2) Previous 7 Critical Peak Days Report, 3) Scenario Comparison – CPP Rate vs. Normal Rate Schedule, and 4) Billing Charges Detail.

Is there a charge associated with SCE's Cost Manager^{sm}?

CPP customers who enroll in SCE's Cost Manager^{sm} will receive a CPP Cost Manager Incentive credit of $19.50 per month. This CPP Cost Manager Incentive credit of $19.50 per month is available for 14 months from initial enrollment, or until December 31, 2005, whichever comes first.

CUSTOMER SPECIFIC ENERGY BASELINE (CSEB)

What is the Customer Specific Energy Baseline (CSEB)?

For SCE to determine how much energy you actually reduced during a CPP event, we must first know what your usage would have been before you reduced power (what the Tariff refers to as your 'Customer Specific Energy Baseline' – CSEB)

How is my CSEB determined?

SCE will use a "10-Day Rolling Average Energy Usage" methodology to calculate your CSEB. Your CSEB is determined on an hourly basis and calculated using your three (3) highest usage days from the previous ten (10) days leading up to a CPP Event (excluding other CPP days, days you were paid to reduce power, or days you were subject to a rotating outage). The hourly CSEB average is then subtracted from the actual amount of kWh used for that hour during the CPP Event to determine the actual kWh reduction. This amount is used to determine if the customer complied with the CPP incentive programs requirements.

INCENTIVE OPTIONS

What are my incentive options?

Participants on the CPP may select from two types of incentive options: ***Bill Protection Incentive*** and/or ***Technical Assistance* Incentive**. Customers may elect to receive one or both of these incentives, which will be available until December 31, 2005, subject to available funds and meeting incentive eligibility requirements.

What is the Bill Protection Incentive?

The Bill Protection Incentive option provides 100% protection against paying energy rates greater than your "otherwise applicable tariff" or standard rate schedule (the rate schedule you transferred from prior to taking part in the CPP) for the first fourteen (14) consecutive months you participate in the CPP program. If you fulfill all obligations necessary (*i.e.,* surveys, site visits, 3% power reduction and your 14-month commitment) for the Bill Protection Incentive, you will receive the full benefits of this incentive.

What are the requirements of the Bill Protection Incentive?

To receive the full benefit of this incentive you must reduce on-peak usage by a minimum of 3% during each CPP Event, averaged over the course of all CPP months during the 14 months of bill protection participation. If you leave the CPP program before the end of your 14 consecutive month commitment, you will not receive bill protection for **any** month you were on the CPP.

Can you provide an example to illustrate what happens if my normal rate schedule is greater than my CPP rate schedule?

Yes. If your standard rate schedule charges are greater than your CPP rate charges, a bill protection credit is not necessary since you are already receiving the benefits of a lower energy bill through your participation on the CPP program. However, if your bill on the CPP rate is higher than it would have been on your standard rate schedule, you will receive a credit on your bill following the end of the bill protection period equal to the difference between what you owe under the CPP rate and what you would have owed on your standard rate schedule.

What happens if I do not achieve a 3% power reduction during CPP events?

All Bill Protection participants will receive the benefit of not paying energy charges greater than their standard rate schedule. However, when a Bill Protection Incentive participant does not achieve the required minimum 3% power reduction, and their normal rate schedule charges are greater than their CPP rate charges, such customer will be billed on their standard rate schedule.

What if I am participating in the Bill Protection Incentive for 12 months and leave the CPP Program?

You will be treated as though you never were participating on the 14-month Bill Protection Incentive.

What is the Technical Assistance Incentive option?

The Technical Assistance Incentive allows CPP participants the opportunity to earn a cash rebate for professional technical assistance that enhances their ability to respond to power reduction events. A cash incentive of up to $50 per kW, (not to exceed the cost of the engineering study) is broken into two payments.

When do I receive my rebate?

Participants will receive up to 50%, or up to $25 per kW, of the incentive payments upon certification by a CEC-approved professional engineer detailing potential on-peak power reduction. To receive the remaining half (approximately $25 per kW) of the Technical Assistance Incentive, customers will have to demonstrate their actual power reduction is equal to at least 50% of their certified potential power reduction during CPP Events, as averaged over four (4) consecutive CPP (summer) months, cumulating before October 1, 2005, or until available funds are exhausted, whichever comes first. If the minimum level of measured power reduction does not occur, CPP participants will not receive the remainder half of the incentive payment.

If I am participating in both the CPP and DBP can I take advantage of the Technical Assistance Incentive through both programs?

No. Such customer can take advantage of the Technical Assistance Incentive in either the CPP or the DBP, but not both.

FOR MORE INFORMATION

How do I sign up?

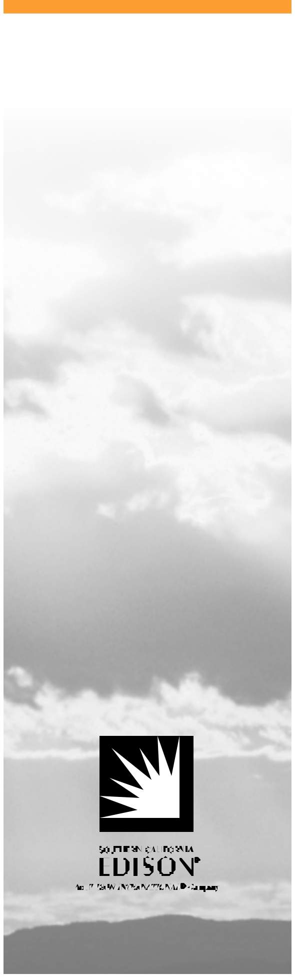
Call your SCE representative for more information on how to change your rate. If you do not have an SCE representative, call the CPP hotline at (626) 302-8320.

Where can I get additional information?

To monitor your monthly power usage, log onto the designated CPP website at www.sce.com/sceenergymanager. You will need to register and SCE will supply you with a log on ID and password. There is no charge for registration and access.

For additional information on the CPP rate option contact your SCE representative, visit www.sce.com or type www.sce.com/DRP to go directly to the Critical Peak Pricing rate option or call the CPP hotline at (626) 302-8320.

SCE has several programs available to help customers better manage their electricity costs, such as rebates, incentives, energy surveys and payment options. If you have questions about other SCE programs, call (800) 990-7788.



INFORMATION ON SCE'S CRITICAL PEAK PRICING RATE OPTION

Lower your business' electric bills by shifting or reducing electricity during "critical peak" summer afternoons

Southern California Edison's (SCE) Critical Peak Pricing (CPP) program may benefit customers, who have at least one account with registered demands greater than 200 kilowatts (kW), and who can reduce, or shift, their power out of the summer season Noon to 6:00 p.m. time period during a CPP Event. Energy rates during summer season CPP Events are approximately three to five times higher than energy rates during summer season non-CPP Events. However, customers on a CPP schedule receive reduced energy rates for all non-CPP usage during the On- and Mid-Peak time periods, year round.

ELIGIBILITY

SCE's CPP program will be available to most customers with demands greater than 200 kW and who rely on SCE for generation, transmission, and distribution of electric services (bundled service customers). The three new schedules are TOU-8-CPP, GS-2-TOU-CPP, and TOU-PA-CPP. Interval metering is required prior to participation and Direct Access customers are not eligible for service on any of SCE's CPP rate schedules.

Those participating in the CPP program must agree to allow the California Energy Commission (CEC), or its contracted agent, to complete any surveys or site visits for measurement and evaluations, as needed to enhance the program, as well as completing all program surveys.

GOOD CANDIDATES FOR CPP

This program may benefit medium to large businesses, as well as agricultural and water pumping customers who have the flexibility of reducing or eliminating on-peak power usage during a CPP Event.

CPP EVENTS

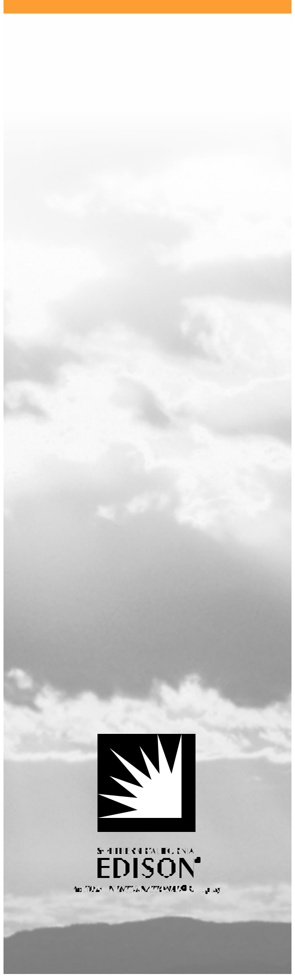
A CPP Event can only be activated during SCE's summer season, between Noon and 6:00 p.m., Monday through Friday, excluding holidays. The maximum number of CPP Events per summer season is 12. The summer season is four months beginning at 12:00 a.m. on the first Sunday in June and continuing until 12:00 a.m. on the first Sunday in October of each calendar year.

THE CPP EVENT "TRIGGERS"

Participants will be notified when SCE determines that a CPP Event is warranted. There are a number of "triggers" that may activate a CPP Event, including high system demand and/or low generation supply, system emergency testing, high market prices, temperature registering at least 87 degrees by 2:00 p.m. — as measured at the Los Angeles Civic Center — or at its discretion, SCE may activate a CCP Event. SCE will adjust the temperature threshold up or down, over the course of the summer season as necessary to achieve the CPP program design basis of 12 CPP Events per summer season.

TYPES OF EQUIPMENT NEEDED

Participants must have an SCE-approved interval metering system capable of recording usage in 15-minute intervals.



Those customers with multiple accounts on the same or adjacent sites may choose to have one or all of their accounts participate on an applicable CPP schedule as long as at least one of the accounts remains above 200 kW and such account is served under a CPP schedule.

NOTIFICATION

Participants will be notified via a telephone call. SCE will begin notifying customers of a CPP Event by 3:00 p.m. the day before an event. If SCE cannot reach the customer on the first attempt, then SCE will make at least two additional notification attempts at 4:00 p.m. and at 5:00 p.m. on the designated primary telephone number. CPP participants may opt to receive additional courtesy notifications via pager, cellular telephone, e-mail or fax. All equipment needed to receive notification will be at the customer's expense. SCE does not guarantee actual receipt of notification. Participating customers will be responsible for all charges incurred during a CPP Event, even if the customer does not receive actual notice.

Are participants required to reduce power during a designated CPP day?

No. However, customers will be charged a premium for kWh usage that occurs during the hours of a CPP Event, which will usually be from Noon to 6:00 p.m. The more customers can reduce their electricity usage during the higher-priced "critical peak" hours, the more likely that customers will save money on their bill.

Do CPP rates vary?

Yes. For any kWh usage that occurs weekdays between the hours of 12:00 p.m. and 6:00 p.m. on a designated CPP day there is a higher on-peak energy charge—or, "critical peak" period charge. Within the critical peak period, there will be two higher priced time periods:

- Noon to 3:00 p.m., when customers will be charged approximately three times their normal rate schedule (otherwise applicable tariff or OAT) on-peak energy rate such as the TOU-8 mid-peak energy rate, and
- 3:00 p.m. to 6:00 p.m., when customers will be charged five times their normal rate schedule (otherwise applicable tariff or OAT) on-peak energy rate such as the TOU-8 on-peak energy rate.

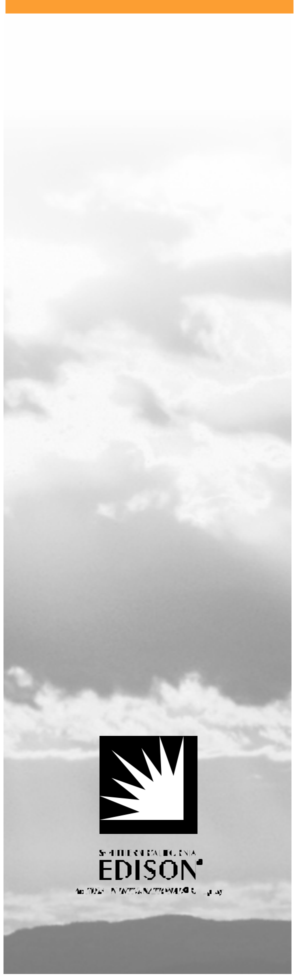
INCENTIVES

Participants on the CPP may select from two types of incentive options: Bill Protection and/or Technical Assistance. Customers may elect to receive one or both of these incentives, which will be available until December 31, 2005 while funds are available.

- **Bill Protection Incentive**

  The Bill Protection incentive option provides 100 percent protection against paying energy rates greater than the CPP participant's "otherwise applicable tariff" or normal rate schedules (such as GS-2 with the Time-of-Use Pricing Option, TOU-8, or TOU-PA-B) for the first 14 consecutive months a customer participates in the CPP program. If a customer should leave the CPP program before the end of their 14-month commitment, the customer will not receive bill protection for **any** month.

  In order to be eligible to receive the benefit of a lower CPP bill, the customer must reduce on-peak usage by a minimum of 3 percent during each CPP Event, as averaged over the course of the CPP months during the 14 months of bill protection. The 3 percent power reduction for each event is compared to the Customer's Specific "10-Day Rolling Average Energy Baseline."



Bill protection benefits are computed on a cumulative basis at the end of the Bill Protection period. If all of the provisions of the Bill Protection Incentive (i.e., surveys, site visits, minimum 3 percent reduction performance standard, and 14-month commitment) are fulfilled, the participant will be eligible for the Bill Protection Incentive. That means that if the actual bill on the CPP rate is higher than it would have been on the customer's normal rate schedule, the customer will receive a credit on the bill following the end of the bill protection period equal to the difference between what the customer owes under the CPP rate and what the customer would have owed on their original rate. If the bill on the CPP rate is lower than the bill would have been on the customer's normal rate schedule, those savings are for the customers to keep. If the normal rate schedule charges are greater than the CPP rate charges, the customer will not receive a bill credit under the Bill Protection Incentive. If customers don't achieve at least a 3 percent power reduction, and their normal rate schedule charges are greater than their CPP rate charges, they will be billed on their normal rate schedule such as GS-2, TOU-8, or TOU-PA-B.

- **Technical Assistance Incentive**
  The Technical Assistance Incentive allows CPP participants the opportunity to earn a cash incentive for professional technical assistance that enhances their ability to respond to power reduction during CPP Events. A cash incentive, of up to $50 per kW, is broken into two parts. Participants will receive 50 percent, or up to $25 per kW, of the incentive for potential on-peak power reductions upon certification by a CEC-approved professional engineer.
  To receive the remaining half of the Technical Assistance Incentive, customers will have to demonstrate that their actual power reduction is equal to at least 50 percent of their certified power reduction per CPP Event as averaged over four (4) consecutive CPP (summer) months, cumulating before October 1, 2005 or until available funds are exhausted, whichever is sooner. If the minimum level of measured power reduction does not occur, CPP participants will not receive the remainder of the incentive.
  The CEC also offers a free program called The Enhanced Automation Program. Customers may call 1-866-732-5591 or access information about the program via the Internet at www.ConsumerEnergyCenter.org/enhancedautomation. This program may help customers become more knowledgeable about their potential for reducing power; however, to receive the first Technical Assistance Incentive, customers will still have to contact a CEC-certified engineering firm.

INCENTIVE AVAILABILITY

The Bill Protection Incentive and the Technical Assistance Incentive will be available to CPP participants from July 1, 2003 until December 31, 2005, while funds are available.

What is the Customer Specific Energy Baseline (CSEB)?

The available Incentives require customers to reduce a certain amount of electricity use during CPP Events in order to claim the benefits of the Incentives. For SCE to determine how much energy each customer actually reduced, SCE needs to know how much energy the CPP participant would have used without any modification to the customer's energy usage.

SCE will use the "10-Day Rolling Average Energy Usage" methodology to calculate each customer's CSEB. The CSEB is determined on an hourly basis using the customer's own average energy usage for the three (3) highest total energy usage days out of the ten (10) days prior to a CPP Event (excluding other CPP days or days the customer was paid to reduce power or the customer was subject to a rotating outage). The CSEB is then subtracted from the actual amount of kWh used for that hour during the CPP Event to determine the actual kWh reduction. This amount will be used to determine if the customer complied with the program and is eligible for the Incentives selected.

Q A Are there other Demand Response Programs that a customer may participate in while participating in the CPP?

Yes, there are other Demand Response Programs customers may participate in while also participating in the CPP: SCE's Scheduled Load Reduction Program (SLRP), the Demand Bidding Program (DBP), or the California Power Authority Demand Reserve Program (CPA DRP). Customers will be eligible to receive credit on SLRP, DBP, or the CPA DRP during a CPP event.

Q A Are there any Demand Response Programs a customer <u>cannot</u> participate in while on the CPP?

CPP participants may *not* participate any Interruptible Program (for example, I-6, I-6-BIP), Optional Binding Mandatory Curtailment Program (OBMC), or the Air Conditioner Cycling Program (ACCP).

FOR MORE INFORMATION

SCE has several programs available to help customers better manage their electricity costs, such as rebates, incentives, energy surveys, and payment options. If you have questions about other SCE programs, call **(800) 990-7788.**

For more information about the Critical Peak Pricing rate option, call the CPP Hotline at **(626) 302-8320,** contact your SCE representative, visit www.sce.com, or type www.sce.com/DRP to go directly to the Demand Response Programs website.

This fact sheet is meant as an aid to understanding SCE's pricing schedules. It does not replace the tariffs. Please refer to the individual rate schedule of interest for a complete listing of terms and conditions of service, which can be viewed or printed via the Internet at **www.sce.com** *(Regulatory Info Center).*

EDISON

SDG&E

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

APPLICABILITY

This schedule is applicable to non-residential customers requesting service on this schedule except that this schedule is closed to additional customers with the exception of customers installing Distributed Generators. Schedule AV-1 customers who transfer to this schedule pursuant to D.02-09-034 and subsequently discontinue service under this schedule cannot return to this rate schedule.

TERRITORY

Within the entire territory served by the Utility.

RATES

T

Description	Transm	Distr	PPP	ND	FTA	TTA Credit	Restruc	CTC	RS	UDC Total
Signaling Equipment Charge ($/new cust)		5,176.16								5,176.16
Contact Closure		87.41								87.41
Basic Service Fees ($/month)										
0-500 kW										
Secondary		48.96								48.96
Primary		48.96								48.96
Secondary Substa.		13982.85								13982.85
Primary Substation		13982.85								13982.85
Transmission		53.84								53.84
> 500 kW										
Secondary		195.80								195.80
Primary		195.80								195.80
Secondary Substa.		13982.85								13982.85
Primary Substation		13982.85								13982.85
Transmission		215.39								215.39
> 12 MW										
Secondary Substa.		22016.80								22016.80
Primary Substation		22016.80								22016.80
Distance Adjust. Fee										
Secondary - OH		1.24								1.24
Secondary - UG		3.20								3.20
Primary - OH		1.23								1.23
Primary - UG		3.16								3.16

(Continued)

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

RATES (Continued)

T

Description	Transm	Distr	PPP	ND	FTA	Restruc	CTC	RS	UDC
Demand Charges ($/kW)									
Non-Coincident									
Secondary	2.65	6.14					0.39	1.37	10.55
Primary	2.57	6.04					0.35	1.32 R	10.28 R
Secondary Substation	2.65						0.39	1.37	4.41
Primary Substation	2.57						0.03	1.32 R	3.92 R
Transmission	2.54						0.03	1.31	3.88
Maximum On-Peak									
Summer									
Secondary		4.02					1.71		5.73
Primary		3.88					1.67		5.55
Secondary Substation							1.71		1.71
Primary Substation							1.22		1.22
Transmission							1.21		1.21
Winter									
Secondary		3.42					0.40		3.82
Primary		3.41					0.39		3.80
Secondary Substation							0.40		0.40
Primary Substation							0.25		0.25
Transmission							0.25		0.25
Power Factor ($/kvar)									
Secondary		0.25							0.25
Primary		0.25							0.25
Secondary Substation		0.25							0.25
Primary Substation		0.25							0.25
Transmission									

(Continued)

SCHEDULE AL-TOU-CP

Sheet 3

GENERAL SERVICE - CRITICAL PEAK

RATES (Continued)

Description	Transm	Distr	PPP	ND	FTA	Restruc	CTC	RS	UDC Total	
Energy Charges ($/kWh)										T
On-Peak - Summer										
Secondary	(0.00204) R	0.00086	0.00614	0.00074	0.00000	0.00053	0.00660	0.00479 I	0.01762 I	
Primary	(0.00204) R	0.00083	0.00614	0.00074	0.00000	0.00053	0.00643	0.00479 I	0.01742 I	
Secondary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00660	0.00479 I	0.01676 I	
Primary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00621	0.00479 I	0.01637 I	
Transmission	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00617	0.00479 I	0.01633 I	
Semi-Peak - Summer										
Secondary	(0.00204) R	0.00086	0.00614	0.00074	0.00000	0.00053	0.00385	0.00479 I	0.01487 I	
Primary	(0.00204) R	0.00083	0.00614	0.00074	0.00000	0.00053	0.00377	0.00479 I	0.01476 I	
Secondary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00385	0.00479 I	0.01401 I	
Primary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00366	0.00479 I	0.01382 I	
Transmission	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00363	0.00479 I	0.01379 I	
Off-Peak - Summer										
Secondary	(0.00204) R	0.00051	0.00614	0.00074	0.00000	0.00053	0.00303	0.00479 I	0.01370 I	
Primary	(0.00204) R	0.00050	0.00614	0.00074	0.00000	0.00053	0.00298	0.00479 I	0.01364 I	
Secondary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00303	0.00479 I	0.01319 I	
Primary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00293	0.00479 I	0.01309 I	
Transmission	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00291	0.00479 I	0.01307 I	
On-Peak - Winter										
Secondary	(0.00204) R	0.00070	0.00614	0.00074	0.00000	0.00053	0.00552	0.00479 I	0.01638 I	
Primary	(0.00204) R	0.00068	0.00614	0.00074	0.00000	0.00053	0.00538	0.00479 I	0.01622 I	
Secondary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00552	0.00479 I	0.01568 I	
Primary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00520	0.00479 I	0.01536 I	
Transmission	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00517	0.00479 I	0.01533 I	
Semi-Peak - Winter										
Secondary	(0.00204) R	0.00070	0.00614	0.00074	0.00000	0.00053	0.00387	0.00479 I	0.01473 I	
Primary	(0.00204) R	0.00068	0.00614	0.00074	0.00000	0.00053	0.00378	0.00479 I	0.01462 I	
Secondary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00387	0.00479 I	0.01403 I	
Primary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00368	0.00479 I	0.01384 I	
Transmission	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00365	0.00479 I	0.01381 I	
Off-Peak - Winter										
Secondary	(0.00204) R	0.00051	0.00614	0.00074	0.00000	0.00053	0.00306	0.00479 I	0.01373 I	
Primary	(0.00204) R	0.00051	0.00614	0.00074	0.00000	0.00053	0.00301	0.00479 I	0.01368 I	
Secondary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00306	0.00479 I	0.01322 I	
Primary Substation	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00296	0.00479 I	0.01312 I	
Transmission	(0.00204) R	0.00000	0.00614	0.00074	0.00000	0.00053	0.00294	0.00479 I	0.01310 I	

Notes: Transmission Energy charges include the Transmission Revenue Balancing Account Adjustment (TRBAA) of ($.00203) per kWh and the Transmission Access Charge Balancing Account Adjustment (TACBAA) of $.00001 per kWh. Restructuring Implementation Rate is comprised of rates for Internally Managed Costs (IMC) and Externally Managed Costs (EMC). PPP rate is composed of: Low Income PPP rate (LI-PPP) $.00200/kWh, Non-low Income PPP rate (Non-LI-PPP) $.00322/kWh (pursuant to PU Code Section 399.8, the Non-LI-PPP rate may not exceed January 1, 2000 levels), and Procurement Energy Efficiency Surcharge Rate of $.00158/kWh. T

(Continued)

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

Rate Components

The Utility Distribution Company Total Rates (UDC Total) shown above are comprised of the following components (if applicable): (1) Transmission (Trans) Charges, (2) Distribution (Distr) Charges, (3) Public Purpose Program (PPP) Charges, (4) Nuclear Decommissioning (ND) Charge, (5) Trust Transfer Amount (TTA), sometimes referred to as Fixed Transition Amount (FTA), (6) Restructuring Implementation Rate (Restruc) which is the sum of the rates for Internally Managed Costs and Externally Managed Costs (7) Ongoing Competition Transition Charges (CTC), and (8) Reliability Services (RS). T

Utility Distribution Company (UDC) Total Rate shown above excludes any applicable commodity charges associated with Schedule EECC (Electric Energy Commodity Cost) and Schedule DWR-BC (Department of Water Resources Bond Charge).

Fixed Transition Amount Adjustment
For residential and small commercial customers as defined in Rule 1 – Definitions, and as described in Public Utilities Code Section 331(h), the rates shown above will be adjusted in accordance with the rates set forth in Schedule FTA.

Time Periods
All time periods listed are applicable to local time. The definition of time will be based upon the date service is rendered.

	Summer May 1 - Sept 30	Winter All Other
On-Peak	11 a.m. - 6 p.m. Weekdays	5 p.m. - 8 p.m. Weekdays
Semi-Peak	6 a.m. - 11 a.m. Weekdays 6 p.m. - 10 p.m. Weekdays	6 a.m. - 5 p.m. Weekdays 8 p.m. - 10 p.m. Weekdays
Off-Peak	10 p.m. - 6 a.m. Weekdays Plus Weekends & Holidays	10 p.m. - 6 a.m. Weekdays Plus Weekends & Holidays

Non-Standard Seasonal Changeover
Customers may select on an optional basis to start the summer billing period on the first Monday of May and to start the winter billing period on the first Monday of October. Customers electing this option will be charged an additional $100 per year for metering equipment and programming.

Franchise Fee Differential
A Franchise Fee Differential of 5.78% will be applied to the monthly billings calculated under this schedule for all customers within the corporate limits of the City of San Diego. Such Franchise Fee Differential shall be so indicated and added as a separate item to bills rendered to such customers.

Large Customer CTC Adjustment
Large Customers, as defined in Rule 1 - Definitions, shall have a Transition Cost Balancing Account (TCBA) bill credit calculated each month that is equal to the CTC rates above, multiplied by the billing determinates as delivered by the Utility to the customer, multiplied by 1.64. This CTC adjustment is effective for a 24-month period, beginning January 1, 2003. Pursuant to D.03-04-027, effective May 1, 2003 through December 31, 2003 the TCBA bill credit shall be calculated using a multiplier of 2.15, and effective January 1, 2004 through December 31, 2004 the multiplier shall be 1.83. Customers that would be billed a CTC for the output of their generator(s) will, for all billing periods commencing after the effective date of this provision, not be billed a CTC for that output. The Utility shall record this amount against the balance in the TCBA.

(Continued)

SCHEDULE AL-TOU-CP

GENERAL SERVICE - CRITICAL PEAK

RATES (Continued)

Large Customer Commodity Credit
Large Customers, as defined in Rule 1 – Definitions, who are receiving bundled service will receive a commodity credit for a 24-month period beginning January 1, 2004. Large Customers will receive a monthly credit in the amount of $0.01313/kWh. This credit represents the return of an overcollection in the large customer subaccount of the Energy Resource Recovery Account (ERRA). D

SPECIAL CONDITIONS

1. Definitions: The Definitions of terms used in this schedule are found either herein or in Rule 1.

2. Period 1G Rates: During the time period in which a Period 1G Signal is in effect the On-Peak rates from the Rates section of this schedule shall apply.

3. Voltage: Service under this schedule normally will be supplied at a standard available Voltage in accordance with Rule 2.

4. Voltage Regulators: Voltage Regulators, if required by the customer, shall be furnished, installed, owned, and maintained by the customer.

5. Reconnection Charge: In the event that a customer terminates service under this schedule and re-initiates service under this or any other schedule at the same location within 12 months, there will be a Reconnection Charge equal to the greater of the Minimum Charge or the Basic Service Fee which would have been billed had the customer not terminated service.

6. Non-Coincident Demand Charge: The Non-Coincident Demand Charge shall be based on the higher of the Maximum Monthly Demand or 50% of the Maximum Annual Demand.

7. Power Factor: The Power Factor rate shall apply to those customers that have a Power Factor Test Failure and will be based on the Maximum Kilovar Billing Demand. Those customers that have a Power Factor Test Failure will be required to pay for the Power Factor Metering that the utility will install.

8. Basic Service Fee Determination. Customers subject to the Signaling Equipment Charge are subject to a reduced Contact Closure Fee of $20.00 per month. The basic service fee will be determined each month based on the customer's Maximum Annual Demand.

9. Interconnection Facilities. Any customer with electric generation facilities shall furnish and maintain control and protective apparatus which the utility may require for the operation of the customer facilities in parallel with the utility's system. The customer will provide a disconnecting device located near the electric meter(s). The utility shall have the right to disconnect the customer's facilities when, in its sole opinion it is necessary to maintain safe electrical operating conditions. Interconnection Facilities shall be accessible at all times to utility personnel.

   Prior to the initial energizing and start-up testing of the customer-owned generator, the customer shall notify the utility and the utility may have a representative present at such test. Additionally, the customer shall comply with all utility rules.

(Continued)

SCHEDULE AL-TOU-CP

Sheet 6

GENERAL SERVICE - CRITICAL PEAK

SPECIAL CONDITIONS (Continued)

10. Peak Shaving. Regardless of any other restrictions within the utility's tariffs, other than the Special Conditions of this tariff, a customer may operate any generation at any time he wishes to reduce his bill on this schedule. A customer operating any generation under this schedule must adhere to the terms and conditions under Rule 21 other than the requirement of being a Qualifying Facility. L

11. Net Energy. Net Energy is energy supplied by the utility minus energy generated by the customer and fed back into the utility's system at any instant in time. Unless covered by a contract, Net Energy shall not be negative. L

12. Limitations of Availability. This schedule shall be available to no more than 5 new customers per calendar month.

13. Tariff Switching Limitation. Customers who elect to discontinue service provided by Schedule AL-TOU-CP will be prohibited from receiving service on Schedule AL-TOU-CP for a 12-month period unless the new service immediately follows service on AL-TOU-CP.

14. Termination of Schedule. This schedule is subject to review and termination in the Utility's next General Rate Case. If the Commission decides to terminate the schedule, a 36-month notice will be given to customers served on this schedule prior to the schedule's termination, unless otherwise decided by the Commission.

15. Optional Billing – Utility Option. After the customer has taken the initial 12-months of service under this schedule, the utility may, at its option, provide all new Schedule AL-TOU-CP customers the lower of the 12-month billing under this schedule or the 12-month billing under their regularly applicable time-of-use schedule. If after being served under this optional billing provision the customer elects to continue service on Schedule AL-TOU-CP, the customer will be required to continue service on this schedule for 12 consecutive months before receiving service on another schedule. This option is not available if the customer has previously taken service on Schedules A-V1, A-V2, A-V3 or I-3.

16. Billing. A customer's bill is first calculated according to the total rates and conditions listed above. The following adjustments are made depending on the option applicable to the customer:

   a. UDC Bundled Service Customers receive supply and delivery services solely from SDG&E. The customer's bill is based on the Total Rates set forth above. The EECC component is determined by multiplying the EECC price for this schedule during the last month by the customer's total usage.
   b. Direct Access Customers purchase energy from an energy service provider (ESP) and continue to receive delivery services from SDG&E. The bill for a Direct Access Customer will be calculated as if it were a UDC Bundled Service Customer, then crediting the bill by the amount of the EECC component, as determined for a UDC Bundled Customer.
   c. Virtual Direct Access Customers receive supply and delivery services solely from SDG&E. A customer taking Virtual Direct Access service must have a real-time meter installed at its premises to record hourly usage, since EECC change hourly. The bill for a Virtual Direct Access Customer will be calculated as if it were a UDC Bundled Service Customer, then crediting the bill by the amount of the EECC component, as determined for a UDC Bundled Customer, then adding the hourly EECC component, which is determined by multiplying the hourly energy used in the billing period by the hourly cost of energy.

Nothing in this service schedule prohibits a marketer or broker from negotiating with customers the method by which their customer will pay the CTC charge.

(Continued)

SCHEDULE AL-TOU-CP

Sheet 7 N

GENERAL SERVICE - CRITICAL PEAK

N

SPECIAL CONDITIONS (Continued) N

17. Insurance: Insurance may not be used to pay Signaled Period 1G rates for willful failure to comply. Each customer must provide the utility with an executed declaration that states "I do not have, and will not obtain, insurance to compensate me in any way for any portion of the bills associated with the Signaled Period 1G rates." Such declaration (Form 142-05209) must be on file with the utility within 30 days of the effective date of the tariffs or the customer will immediately begin service on Schedule AL-TOU in lieu of continued service on Schedule AL-TOU-CP.

18. Electric Emergency Load Curtailment Plan: As set forth in CPUC Decision 01-04-006, all transmission level customers except essential use customers, OBMC participants, net suppliers to the electrical grid, or others exempt by the Commission, are to be included in rotating outages in the event of an emergency. A transmission level customer who refuses or fails to drop load shall be added to the next curtailment block so that the customer does not escape curtailment. If the transmission level customer fails to cooperate and drop load at SDG&E's request, automatic equipment controlled by SDG&E will be installed at the customer's expense per Electric Rule 2. A transmission level customer who refuses to drop load before installation of the equipment shall be subject to a penalty of $6/kWh for all load requested to be curtailed that is not curtailed. The $6/kWh penalty shall not apply if the customer's generation suffers a verified, forced outage and during times of scheduled maintenance. The scheduled maintenance must be approved by both the ISO and SDG&E, but approval may not be unreasonably withheld.

19. Memorandum Account Balances: Pursuant to D.02-04-060, customers who were interruptible customers for 12 months or less as of January 26, 2001, have the option to reconcile their account balances incurred between November 1, 2000 and January 25, 2001. Customers who remain on Schedule AL-TOU-CP, or its predesessor, shall be allowed to opt-out effective with the next billing cycle after completion of the notification period, and will be provided a rebate of memorandum account penalty amounts, but shall not be permitted to return to an interruptible tariff before 12 months after the opt-out is effective. Customers who opted-out or were switched to other schedules prior to June 30, 2001, shall be provided a rebate of memorandum account penalty amounts.

20. Other Applicable Tariffs: Rules 21, 23 and Schedule E-Depart apply to customers with generators. N

BILL PROTECTION
Application

California Public Utilities Commission Decision 03-06-032 authorizes Bill Protection for customers electing SDG&E commodity service on Schedule EECC-CPP (Critical Peak Pricing) or Schedule EECC-HPO (Hourly Pricing Option). Bill Protection is available to customers during the first fourteen (14) months the customer is receiving service, but no later than December 31, 2005. Bill Protection provides that participating customers will pay no more for energy commodity service than they would have had they remained on Schedule EECC.

Pursuant to the Schedule EECC-CPP and Schedule EECC-HPO tariffs, customers requesting service on either Schedule EECC-CPP or Schedule EECC-HPO may elect the Bill Protection option. This Application acknowledges Acceptance or Rejection of Bill Protection.

In conjunction with completing this Application, customers must complete a Rate Change Authorization Form requesting service on either Schedule EECC-CPP or Schedule EECC-HPO.

Customer Declaration

I, ______________________________ (name) hereby state that I am the ______________________________ (title) of ______________________________ (company), and am authorized to make this declaration on behalf of my company for the following account(s):

Bill Protection

Account Number	Site Address	Option	
____________	____________	☐ Accept	☐ Decline
____________	____________	☐ Accept	☐ Decline
____________	____________	☐ Accept	☐ Decline
____________	____________	☐ Accept	☐ Decline
____________	____________	☐ Accept	☐ Decline

Attach additional Account Information to this sheet if required. (Sheet ______ of ______)

____
(Print Name)

______________________________ ______________
(Signature) (Date)

Form No. (142-05211) (07/03)

APPENDIX B
DBP MATERIALS (TARIFFS, BROCHURES)

PG&E

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM

APPLICABILITY: The Schedule E-DBP Demand Bidding Program (Program) offers customers incentives for reducing energy consumption and demand when requested by Pacific Gas and Electric Company (PG&E) to increase system reliability. This Program is optional for customers with billed maximum demand of 200 kilowatts (kW) or greater during any one (T) of the past 12 billing months and who voluntarily commit to reduce a minimum of 100 kW (T) each hour for each service account during an E-DBP Event. PG&E will determine E-DBP Bid acceptances for energy reductions. Interval metering is required to receive service under this Program. Customers must receive service on a demand Time-of-Use (T) (TOU) electric rate schedules. Customers on Schedules AG-R, AG-V, or S are not (N) eligible for this program. A customer is not eligible to participate in this program if the | revenue metering configuration is either net sale or Wholesale Transaction as specified | in PG&E's Interconnection Handbook. A customer with multiple meters at a single site (N) may qualify for the program under the specified multiple meter provisions of this tariff. This schedule is available until modified or cancelled by the California Public Utilities Commission (CPUC).

TERRITORY: This schedule applies everywhere PG&E provides electric service.

ELIGIBILITY: This schedule is available to individual PG&E bundled-service customers and Direct (T) Access customers. Each customer must take service under the provisions of their | otherwise-applicable rate schedule. Customers participating in the Program must be on | an eligible rate schedule and commit to reduce load by at least 100 kW during a market (T) price DBP event and agree to reduce their load by their Committed Load Reduction Amount in the event of an Emergency DBP event.

Customers on this tariff must agree to allow the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to enhance the program. Customer must submit a signed Authorization To Receive Customer Information or Act On A Customer's Behalf form giving the CEC authorization to request billing history and meter usage data information.

Customers must submit a signed Interruptible Program Agreement (Form 79-976) and (T) an Customer Agreement and Password Governing use of Internet-Based Software | Agreement (Form 79-977) in order to establish service. In addition, customers must (T) have the required metering and notification equipment in place prior to participation in this Program.

Customers who are "Essential Customers" under PG&E's Electric Emergency Plan and as defined by the Commission in Rulemaking 00-10-002, must submit to PG&E a written declaration that states that the customer is, to the best of that customer's understanding, an Essential Customer under Commission rules and exempted from rotating outages. The declaration must also state that the customer voluntarily elects to participate in this interruptible program for part or all of its load upon request by PG&E under the terms of E-DBP, while continuing to adequately meet its essential needs with backup generation or other means. In addition, an Essential Customer may commit no more than a total of 50 percent (50%) of its average peak load to all interruptible programs for each participating account.

Customers that have multiple meters located at a single site (e.g., contiguous property, (T) campus facilities, business parks) with individual meters that have demands less than (T) 200 kW (as described in the Applicability Section) may participate in this program under the provisions stated in Multiple Meter Customer Section of this tariff.

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

METERING EQUIPMENT:

Each participating customer account must have an interval meter capable of recording usage in 15-minute intervals installed that can be read remotely by PG&E. A Meter Data Management Agent (MDMA) may also read the customer's meter on behalf of the customer's Energy Service Provider (ESP) if a customer is receiving Direct Access Service. Metering equipment (including telephone line, cellular, or radio control communication device) must be in operation for at least ten (10) days prior to participating in the program to establish baseline. If required, for bundled service customers, PG&E will provide and install the metering equipment at no cost to the customer through December 31, 2004. PG&E will also provide meter data retrieval at no cost to those bundled customers receiving free meters through this tariff until otherwise directed by the CPUC. (N) (T) (T) (D)

Direct Access Serivce Customers – If PG&E is the Meter Data Management Agent (MDMA) on behalf of the customer's Energy Service Provider, no additional fees will be required from the Direct Access service customer. On the other hand, if the Direct Access service customer uses a third-party MDMA, the customer will be responsible for any and all costs associated with providing PG&E acceptable interval data into the PG&E system on a daily basis. This includes any additional metering or communication devices that may need to be installed, and any additional fees assessed by the customer's ESP. Prior to customer's participation in the program, the customer must be able to successfully transfer meter data to PG&E's specification on a daily basis for a period of no less than ten (10) days to establish their baseline. (N)

NOTIFICATION EQUIPMENT:

Customers, at their expense, must have access to the Internet and an e-mail address to receive notification regarding program operations and to submit E-DBP Bids. In addition, all customers must have, at their expense, an alphanumeric pager that is capable of receiving a text message sent via the Internet. A customer cannot participate in the Program until all of these requirements have been satisfied. (T)

If an E-DBP Event occurs, customers will be notified using one or more of the above-mentioned systems. PG&E will make best efforts to notify customers, however it is the customer's responsibility to receive such notice and to check the PG&E website to see if the Program is activated. No evaluation will be performed, nor payment made, for load reductions undertaken during an E-DBP Event without such advance confirming notification. PG&E does not guarantee the reliability of the pager system, e-mail system or Internet site by which the customer receives notification.

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

E-DBP EVENT NOTICE:

A. Day-Ahead Market Price E-DBP Event Notice

By 2:00 p.m. (Pacific Time), PG&E may implement a Day-Ahead E-DBP event in those hours where the forecasted Day-Ahead hourly market prices equal or exceed $0.15 per kWh for four consecutive hours between 12:00 noon and 8:00 p.m. the next day. PG&E will notify customers of such event, and will post the hourly market price on the notice through the program's web site by 3:00 p.m. the day preceding the E-DBP event. Market Price E-DBP Event Notices will be issued on Friday by 3:00 p.m. for events occurring on the following Monday, or for events that are issued for Tuesday following a holiday that falls on Monday.

For the Day-Ahead E-DBP Event, participating customers shall submit bids to the program's website between 3:00 p.m. and 4:00 p.m. on the day preceding the curtailment event. After 5:00 p.m., customers will receive confirmation of bid acceptance or rejection on the web site. Unless a specific megawatt (MW) limit is requested, PG&E will deem all bids acceptable from customers. In the event bids are restricted, PG&E will accept bids on a first-come, first-served basis. If the customer's bid is accepted, the customer must reduce their kW load for each participating account to or above their accepted bid amount for each hour of their bid. Once a customer's bid has been accepted, that bid shall not subsequently be rejected by the utility, but payment shall continue to be based on the customer's actual performance.

B. System Emergency E-DBP Events

PG&E can issue a System Emergency E-DBP Event when it deems that there are outstanding system issues that may affect system reliability. Emergency events can be issued for the hours of between 12:00 noon and 8:00 p.m., weekdays only, excluding holidays. PG&E will notify customers of a System Emergency E-DBP (T)
Event through the program's web site, and participants must reduce their loads by (T)
their committed load reduction amount within one (1) hour of notification.

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

ENERGY BID:

A. Market Price E-DBP Events

E-DBP bidding shall be accepted for non-holiday weekdays only. The E-DBP Bid shall indicate the amount of kW curtailment that the participant is offering for each hour of the E-DBP Event. The participant may submit only one bid for each E-DBP Event. Each bid must be for a minimum of two (2) hours and must be for consecutive hours during the E-DBP Event. The customer's bid must meet the minimum energy reduction threshold of 100 kW for each hour in the E-DBP Event. The participant must submit their bid within the timeframe specified in the Market Price E-DBP Event Notice section.

Customers, at their option, may designate a pre-bid amount in which they will only be notified of an E-DBP event when the price trigger meets or exceeds their specified pre-bid amount. The customer's pre-bid amount shall be designated on the customer's Demand Response Program Agreement (Form 79-976). (T)

B. System Emergency E-DBP Events

Once notified, the customer must log into the Program's Internet web site and acknowledge participation in the curtailment. Failure to acknowledge a curtailment notice does not release the customer from their obligation to participate. The participant must reduce their load by their Committed Load Reduction amount within the time frame specified in the notice.

E-DBP WEBSITE: Customers must submit a Market Price E-DBP Bid through PG&E's designated Internet website. Each bid submitted via the website shall be for an E-DBP Event that can take place on the next eligible day, any weekday, excluding holidays, following the bid submission. Notification of E-DBP Bid acceptances will be posted to PG&E's website. Posting of accepted bids may be delayed due to unforeseen problems in transmitting or receiving the bids. PG&E cannot guarantee the reliability of the Internet site by which customers submit bids and receive information regarding this Program. PG&E may use and accept alternate means of notification as necessary. PG&E will communicate the following information on the website regarding accepted E-DBP Bids:

1. The Date and the Time Period of the E-DBP Events; and

2. The customer's specific energy baseline (CSEB), based on the hourly average of the three (3) highest energy usages on the immediate past ten (10) similar days. The three (3) highest energy usage days will be deemed as those days with the highest total kilowatt hour usages between noon and 8:oo p.m. The past ten (10) similar days will include Monday through Friday, excluding holidays, and will additionally exclude days when the customer was paid to reduce load on an interruptible or other curtailment program or days when rotating outages are called.

3. The hourly pricing incentive that PG&E intends to offer for qualifying load reductions.

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

PROGRAM TESTING: PG&E may activate an E-DBP Event with a simulated emergency event test trigger twice per year. Each emergency test event shall be no longer than four (4) hours. During such a test, the customer shall be responsible for curtailing load consistent with the terms of this schedule. Participants will receive incentive payment for qualifying load reduction based on a System Emergency E-DBP Event. (T)

INCENTIVE PAYMENTS: PG&E will evaluate and pay for the customer's hourly load reductions realized under the Program within ninety (90) days after each E-DBP Event, depending on where the E-DBP Event falls within the participant's actual billing cycle. The incentive payments will be reflected in the customer's regular monthly bill as an adjustment.

A. Market Price E-DBP Event Incentive

Incentives will be calculated on an hourly basis, and will be equal to the product of the forecasted hourly market price of the E-DBP Event (when the forecast market price is equal to or exceeds $0.15/per kWh) and the qualified kWh energy reduction for each hour a bid was accepted.

Energy reduction for a given Market Price E-DBP Event hour will be determined as the difference between the customer specific energy baseline (CSEB) for that hour and the customer's actual energy usage during that hour. Participants will only be paid for a maximum of 150 percent (150%) of their accepted bid (kW) load drop measured on an hourly basis. Participants must drop at least 50 percent (50%) of their bid load to qualify for any payment in any hour. In no case will a customer receive a credit payment for a given hour if it does not meet, in that hour of the event, the minimum energy reduction of 100 kW.

B. System Emergency E-DBP Event Incentive

Incentives will be calculated on an hourly basis, and will be equal to the product of $0.50 per kWh and the qualified kWh energy reduction for each hour of the E-DBP Event.

Energy reduction for a given System Emergency E-DBP Event hour will be determined as the difference between the customer specific energy baseline (CSEB) for that hour and the customer's actual energy usage during that hour. Participants will only be paid for a maximum of 150 percent (150%) of their committed load reduction measured on an hourly basis. Participants must drop at least 50 percent (50%) of their committed load reduction to qualify for any payment in any hour. In no case will a customer receive a credit payment for a given hour if it does not meet, in that hour of the event, the minimum energy reduction of 100 kW.

Participants will not receive more than one incentive payment for the same event. If both a System Emergency E-DBP Event and a Market Price E-DBP Event should occur during the same hour, the participant will receive the higher of the two incentive levels.

(Continued)

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

MULTIPLE METER CUSTOMERS: Customers that have multiple meters located at a single site (e.g., contiguous property, campus facilities, business parks) are eligible for the program under the following conditions:

1. Each individual service account must currently take service on an applicable PG&E rate schedule and have an installed interval meter as stated in the Applicability Section of this schedule. If necessary, a service account may change rate schedule and PG&E will provide and install an interval meter. Fees associated with a rate change will be the responsibility of the customer.

2. The customer must have at least one service account with billed maximum demand of 200 kW or greater for at least one or more of the past 12 billing months within the customer's site, and on of these service accounts must be designated as the primary account for the multiple-meter customer group. A signed Demand Response Program Agreement (Form 79-976), and an Customer Agreement and Password Agreement Governing use of Internet-Based Software Agreement (Form 79-977) must be submitted under the name of the primary account. (T)

3. All service accounts that are part of the multiple-meter customer group must take service from PG&E under the same corporate tax identification number and be listed on the Demand Response Program Agreement. Individual accounts, (excluding the lead account), with less than 200 kW (as described in the Applicability Section) may participate in the program as part of the multiple-meter customer group. (T)

4. Energy reduction during a DBP event will be based on individual service account performance and will be calculated as described in the Incentive Payment section of this tariff.

TECHNICAL ASSISTANCE INCENTIVES: The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances the customer's ability to respond to curtailment requests for on-peak demand reductions. Customers shall receive a rebate (not to exceed actual costs) based on $50 per kW of curtailable on-peak load reduction nominated by the customer through a signed Technical Assistance Incentive Application (Form 79-1005). Curtailable on-peak load shall be defined as existing load that is temporarily reduced or shifted to another time period as a result of an E-DBP Event being issued.

Customer shall receive 50% of the rebate following submission of a signed Application prepared in conjunction with an audit conducted by a CEC-certified Professional Engineer (P.E.) of potential on-peak load reductions. Customers shall receive the remainder of the rebate after demonstrating peak demand reduction of at least 50% of their nominated load drop as averaged over all DBP events or tests. The demand (energy) reduction will be determined by the same methodology as defined in the Incentive Payment section of this schedule. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate. A minimum of two (2) DBP events or tests must be successfully completed to calculate the average performance level and award incentive.

The technical assistance incentives will be available to participants until December 31, 2005, or until the funding for the transitional incentives are exhausted.

Participants receiving a technical assistance incentive under the Critical Peak Pricing Program (Schedule E-CPP) are ineligible to receive a technical assistance incentive for the same consulting study under this schedule.

SCHEDULE E-DBP—DEMAND BIDDING PROGRAM
(Continued)

FAILURE TO REDUCE LOAD: Except as provided in the Incentive Payment section of this schedule, no additional monetary penalties will be assessed under this Program for a customer's failure to comply (reduce energy) during any or all hours of an E-DBP Event.

PROGRAM TERMS: Customers' participation in this tariff will be in accordance with Electric Rule 12. Customers may terminate their E-DBP agreement by giving a minimum of 30 days' written notice. Cancellation of the agreement will become effective with the first regular billing cycle after the 30-day notice period. PG&E may terminate the service agreement at any time after giving a thirty (30) day written notice to participants.

INTERACTION WITH CUSTOMER'S OTHER APPLICABLE PROGRAMS AND CHARGES: Participating customers' regular electric service bills will continue to be calculated each month based on their actual recorded monthly demands and energy usage.

Customers who participate in a third-party sponsored interruptible load program must immediately notify PG&E of such activity. DBP participants shall not participate in the California Power Authority Demand Reserves Partnership (CPA-DRP) program.

Load can only be committed to one program for any given hour of a curtailment, and customers will be paid for performance under only one program for a given load reduction. In other words, should another demand response program be activated, while an E-DBP Event is in progress, those events will supersede an E-DBP Event, and no E-DBP incentive payments will be applied for those overlapping hours. E-DBP customers shall not participate in the California ISO's Participating Load Program (Supplemental and Ancillary Services), California Power Authority's Demand Reserves Partnership (CPA-DRP) program, or any other pay for performance program. (T)

Customers enrolled in the Scheduled Load Reduction Program (Schedule E-SLRP) may participate in E-DBP during the days when the customer's load is not scheduled for curtailment under the E-SLRP program.

EMERGENCY STANDBY GENERATION: Customers may achieve energy reductions by operating back-up or onsite generation. The customer will be solely responsible for meeting all environmental and other regulatory requirements for the operation of such generation.

DIRECT ACCESS CUSTOMERS (N) Customers participating in this program and receiving service under Direct Access must notify their Energy Service Provider that they are participating in this program and when they participate in a DBP event. The per even notification must include the amount of hourly load bid for a day-ahead event or the customer's Committed Load Reduction Amount for an emergency DBP event. PG&E reserves the right to require that the Direct Access customer's Scheduling Coordinator (SC) must submit a Scheduling Coordinator to Scheduling Coordinator (SC to SC) trade with the service electric utility. If PG&E imposes this requirement, then: (1) the SC to SC trade must be submitted in a timeframe that complies with the California Independent System Operator's (ISO's) requirements; and (2) the Direct Access customer is responsible for all additional costs incurred by the serving utility if the customer's SC fails to submit a SC to SC trade, or if the SC to SC trade is not accepted by the ISO because of an action or inaction of the customer's SC. (N)

SCE

Schedule DBP
DEMAND BIDDING PROGRAM

Sheet 1

APPLICABILITY

The Demand Bidding Program (DBP) is a bidding program that offers Day-Ahead and Day-Of price incentives to customers for reducing energy consumption during a DBP Event, which may be called during any of the following periods: (1) when the California Independent System Operator (CAISO) determines that load relief may be needed in a Day-Of Commitment to mitigate shortages in operating reserves that have the potential to lead to a warning notification, Stage 1, 2, or 3 Emergency, (2) Emergency testing, (3) Price triggers activate a Day-Ahead Commitment. This Schedule is optional for Bundled Service Customers with maximum demands above 200 kW, defined herein as registered Maximum Demand of greater than 200 kW in any three months during the preceding twelve months, who are not receiving service under Real Time Pricing (RTP) rate schedules or who are not participating in the CAISO's Ancillary Services Load Program or the California Power Authority's Demand Reserves Program (DRP). Customer service accounts served under Schedule S are not eligible for service under this Schedule. Participants must commit to reduce a minimum of 100 kW per hour for each service account participating, during a DBP Event. Participants may not aggregate service accounts when submitting a bid. Under this Schedule, the customer shall bid certain amounts of energy that the customer commits to reduce. An Interval metering system, as defined in Special Condition 6 is required to receive service under this Schedule. Service under this Schedule is subject to meter availability. (T) | (T) (C) | | | (C) (T) (C) (C) (C) (T) (D)

TERRITORY

Within the entire territory served.

RATES

All other charges and provisions of the customer's otherwise applicable tariff (OAT) shall apply, except a participating customer that reduces energy during a DBP Event will receive a discount in the form of a credit on its bill or will receive a separate check within 90 days of the DBP Event. (T)

DBP Credit per kWh:

Day-Ahead Commitment participants shall receive a credit equal to the accepted price offer, as defined in Special Condition 2.a. below, times the amount of actual load reduction, which must be at least 50 percent of the customer's Energy Bid. Day-Of Commitment participants shall receive a credit equal to $0.50 per kWh of actual load reduction, which must be at least 50 percent of the customer's Committed Load Reduction. Both Day-Ahead and Day-Of DBP credits will not apply to any amount of actual load reduction that is greater than 150 percent of the customer's Energy Bid/Committed Load Reduction and at no time will a DBP credit apply during hours a customer's actual load reduction is less than the Minimum Energy Reduction Threshold, as defined in Special Condition 11. (C) | | | | | (C)

(Continued)

Schedule DBP Sheet 2
DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS

1. Agreement. Participating customers must sign a DBP Agreement including the Non-Disclosure Agreement and certificate (Form 14-741). This Agreement shall become effective after SCE determines the customer has complied with the installation of the required metering equipment in accordance with the terms and conditions of the Agreement and this Schedule. (T) (T)

2. DBP Event. DBP Events may be triggered when any of the following conditions are met: (T)

   a. DBP Event for the Day-Ahead Commitment: A price trigger will determine if a Day-Ahead DBP Event will occur. SCE's procurement department shall forecast an hourly price offer on a day-ahead basis by 2:00 p.m. and this price offer will remain confidential, which participating customers must agree to by signing Form 14-741 prior to being served under this Schedule. When the forecast price offer exceeds $0.15 per kWh for four consecutive hours between Noon and 8:00 p.m., a Day-Ahead DBP Event will occur. (T) (N)(D)

      Once triggered, a DBP Event for the Day-Ahead Commitment may be in effect between Noon and 8:00 p.m. Monday through Friday, excluding holidays.

   b. DBP Event for the Day-Of Commitment: An Emergency Trigger will activate a DBP Day-Of Event. An Emergency is defined as a necessity to offset outstanding system issues that may affect system reliability. SCE may call a Day-Of DBP Event based upon a Warning Notice or a more advanced CAISO Notice (Stage 1, 2, or 3 Emergency) when issued by the CAISO by 11:00 a.m. on the day of the DBP Event.

      Once triggered a DBP Event for the Day-Of Commitment may be in effect between 3:00 p.m. and 8:00 p.m. Monday through Friday, excluding holidays.

      A DBP Day-Of Emergency Test Event may be activated by SCE without meeting the definition of an actual emergency, as defined above. No more than 2 test events may be activated per year, lasting no longer than 4 hours each. Participants must meet the same requirements as those of an actual DBP Day-Of Event to receive a DBP Day-Of credit during a Day-Of Emergency Test Event. (N)

3. Energy Bid. The amount of kW per hour (kWh usage) that a customer commits to reduce during a DBP Event is the customer's Energy Bid. The customer will be permitted to submit only one Energy Bid for a requested curtailment day, in consecutive hours, with a minimum duration of two hours. A customer whose Energy Bid is accepted in the Day-Ahead Commitment for a set day may not participate in the Day-Of Commitment for that same day. The amount of kW may vary from hour to hour within a single Energy Bid. For each DBP Event, the customer must submit its Energy Bid for a minimum energy reduction not less than 100 kW per hour in the Event. The customer shall not aggregate service accounts when submitting a bid. Energy Bids shall be processed for non-holiday weekdays only. In accordance with Special Condition 4 of this Schedule, the customer can determine if its bid for an individual DBP Event was accepted by logging onto SCE's designated Internet website. (D) (C) (C)

(Continued)

Schedule DBP
DEMAND BIDDING PROGRAM
Sheet 3

(Continued)

SPECIAL CONDITIONS (Continued)

4. Notification of DBP Events and Submission and Acceptance of Energy Bids. (C)

a. Notification of DBP Events. SCE will notify customers of a DBP Event via SCE's notification system. SCE's primary notification method will be via telephone call, but the customer may also elect to receive notification via pager, electronic mail, cellular telephone, or by fax as a courtesy. SCE will begin to notify customers by 3:00 p.m. the day before a Day-Ahead event and by 12:00 p.m. the same day of a Day-Of event and will continue to attempt to notify customers two more times directly following the first notification. SCE does not guarantee customer receipt of the notification.

b. Submission of Day-Ahead/Day-Of Energy Bids. Customers shall submit Day-Ahead Energy Bids via SCE's designated Internet website only, no later than 4:00 p.m. on the day preceding the Event and no later than 1:00 p.m. for a Day-Of event.

c. Acceptance of Energy Bids. Within one hour after the bid submission deadline, SCE shall evaluate each timely submitted Energy Bid, accept or reject each Energy Bid, and notify the customer of the result. Bids shall be accepted for non-holiday weekdays only. Once an Energy Bid has been accepted, the bid shall not subsequently be rejected by SCE, and payment shall be based on the customer's actual performance. SCE will notify customers of the acceptance or rejection of Energy Bids via the DBP website at least one hour prior to the DBP Event. SCE does not guarantee the reliability of the Internet site by which customers submit Energy Bids and receive information regarding this Schedule.

5. Customer Specific Energy Baseline (CSEB). The CSEB is used to determine the customer's Recorded Reduced Energy for each DBP Event. The CSEB will be determined by using a 10-day rolling average energy usage profile of the immediate past 10 similar days prior to the DBP Event. Then, the three highest usage days consisting of the time periods from Noon to 8:00 p.m. will be extracted from the 10 days for the CSEB. The CSEB will be calculated on an hourly basis from Noon to 8:00 p.m. using the average of the same hour for the highest three similar days. The CSEB will include Monday through Friday, excluding holidays, and will additionally exclude days when the customer was paid to reduce load on an interruptible or other curtailment program or when customers were subject to rotating outages. The CSEB will be determined by SCE at the time the customer (C)
is billed following a DBP Event. The CSEB may vary for each hour and for each Event.

(D)

(Continued)

Schedule DBP Sheet 4
DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

6. Required Metering and Internet Communication Equipment. Prior to participation on this Schedule, a customer must have Interval Metering and Internet access to SCE's designated Internet DBP website notifications. Metering equipment must be in operation for at least ten (10) days prior to participation on this Schedule to establish a customer's Customer Specific Energy Baseline (CSEB). For participating service accounts without the required interval metering SCE will provide and install such equipment at no cost to the customer through December 31, 2004.

   Bundled service customers receiving an interval meter at no charge from SCE through this Program will be able to continue to use it at no additional cost even after the Program is terminated, provided that the customer remained in the Program continuously for a minimum period of one year. A customer who receives an interval meter through this Program but later elects to leave the Program prior to the one-year anniversary date, or is terminated for cause, will reimburse SCE for all expenses associated with the installation and maintenance of the meter. (N)

7. Associated Accounts: Customers served under this Schedule with otherwise eligible accounts located on the same or immediately adjacent Premises as the account currently being served under this Schedule may choose to have one or all of their accounts served under this Schedule without meeting the Maximum Demand requirements, as long as at least one account remains above 200 kW at all times and such account receives service under this Schedule, and as long as each associated account meets all other requirements of this Schedule, including the Minimum Energy Reduction Threshold.

8. Cancellation of Energy Bid Solicitation. An Energy Bid solicitation may be cancelled any time prior to its acceptance by SCE.

9. Recorded Reduced Energy. The Recorded Reduced Energy equals the difference between the customer's CSEB and the recorded kWhs of an accepted Energy Bid during a DBP Event.

10. Credit Payments. Credit payments will only apply to the portion of Recorded Reduced Energy in any hour that falls within a +/- 50 percent bandwidth of the customer's Energy Bid. At no time will a DBP credit apply during hours a customer does not meet the Minimum Energy Reduction Threshold.

11. Minimum Energy Reduction Threshold. The minimum energy reduction must be at least 50 percent of the customer's Energy Bid and greater than or equal to 100 kW.

(Continued)

Schedule DBP — Sheet 5
DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

12. Technical Assistance Incentive Option: A Technical Incentive is available to customers served under this Schedule. This incentive option expires on December 31, 2005, or until funding is exhausted. Customers who meet all of the conditions outlined below may participate: (N)

   a. The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances a customer's ability to respond to curtailment requests for on-peak demand reductions. A customer requesting this incentive may receive a rebate (not to exceed costs) based on $50 per kW of curtailable on-peak load reduction nominated by the customer through a signed Technical Assistance Incentive Application (Form 14-752). Curtailable on-peak load shall be defined as existing load that is temporarily reduced or shifted to another time period as a result of an DBP Event being issued.

   b. The customer shall receive an incentive payment equal to 50 percent of the rebate following submission of a signed Application (Form 14-752) prepared in conjunction with an audit conducted by a CEC-certified Professional Engineer (P.E) of potential on-peak load reduction.

   c. The remaining 50 percent of the rebate shall be paid after the customer has demonstrated actual peak demand reductions equal to at least 50 percent of their nominated load drop as averaged over all DBP Events or Tests. A mimimum of two (2) DBP Events or Tests must be successfully completed to calculate the average performance level and award incentive.

   d. Special Condition 5 shall be used in measuring demand reduction. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate.

   e. Participants receiving a technical assistance incentive under a Critical Peak Pricing (CPP) rate schedule are ineligible to receive a technical assistance incentive for the same consulting study under this schedule.

13. Customer Site Visits: All customers served under this Schedule agree to allow the California Energy Commission, or its contracted agents, to conduct site visits for measurement and evaluation, and further agree to complete all program evaluation surveys. Upon request, the customer shall be required to authorize the release of their information to the CEC, or it's agent, for evaluation purposes. (N)
(N)
(N)

(Continued)

Schedule DBP Sheet 6
DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

14. Relationship to Other Interruptible/Curtailment Programs. Customers currently taking service under the California Power Authority Demand Reserves Partnership Program (CPA DRP) are not eligible to receive service under this Schedule. Customers currently taking service under a Critical Peak Pricing (CPP) schedule, Schedule I-6, Schedule I-6-BIP, Schedule TOU-8-SOP-I, Schedule AP-I, Schedule TOU-PA-SOP-I, Schedule OBMC, Schedule SLRP may be eligible for this program. However, under no circumstances will a customer taking service under this Schedule concurrently with any of the fore mentioned applicable Schedules/Programs receive more than one incentive payment for the same interrupted/curtailed load. Should either the CAISO or SCE activate a CPP Event, or a notice of Interruption on an Interruptible Schedule for which a DBP Customer participants on, as set forth in the provisions of the applicable rate schedules, during any period that overlaps with the period of a DBP Event under this Schedule, no credits under this Schedule will apply during the period of overlap and all provisions of the customer's CPP Schedule, or Interruptible Schedule shall prevail. For the duration of this Schedule, customers enrolled in this program shall not participate in any CAISO Ancillary Services Load Program or pay for performance program. (C) | | | (C) (C) | (C) (C) (C)

15. Customer-Owned Electrical Generating Facilities. Customers may achieve energy reductions by operating back-up or onsite generation. The customer will be solely responsible for meeting all environmental and other regulatory requirements for the operation of such generation.

    a. Where customer-owned electrical generating facilities are used to meet a part or all of the customer's electrical requirements, service shall be provided concurrently under the terms and conditions of Schedule S and this Schedule. Parallel operation of such generating facilities with SCE's electrical system is permitted. A Generation Agreement is required for such operation.

    b. Customer-owned electrical generating facilities used solely for auxiliary, emergency, or standby purposes (auxiliary/emergency generating facilities) to serve the customer's load during a period when SCE's service is unavailable and when such load is isolated from the service of SCE are not subject to Schedule S. However, upon approval by SCE, momentary parallel operation may be permitted in order for the customer to avoid interruption of load during a DBP Event or to allow the customer to test the auxiliary/emergency generating facilities. A Momentary Parallel Generation Contract is required for this type of service.

(Continued)

Schedule DBP — Sheet 7

DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

16. Failure to Reduce energy. No penalties will be assessed under this Schedule for a customer's failure to comply to reduce energy during a DBP Event.

17. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages.

Sub-transmission customers, except for those customers exempt from rotating outages, are to be included in controlled, rotating outages when required by the Independent System Operator (ISO). To the extent feasible, SCE will coordinate rotating outages applicable to Sub-transmission customers who are fossil fuel producers and pipeline operators and users to minimize disruption to public health and safety. SCE shall not include a Sub-transmission customer in an applicable rotating outage group if the customer's inclusion would jeopardize electric system integrity. Sub-transmission customers who are not exempt from rotating outages, and seek such exemption, may submit an Optional Binding Mandatory Curtailment (OBMC) Plan to SCE in accordance with Schedule OBMC. If SCE approves a customer's OBMC Plan, the customer will become exempt from rotating outages and will be subject to the terms and conditions of Schedule OBMC and its associated contract.

Non-exempt Sub-transmission customers shall be required to drop their entire electrical load during applicable rotating outages by either (1) implementing the load reduction on their own initiative, in accordance with subsection a, below; or (2) having SCE implement the load reduction through remote-controlled load drop equipment (control equipment) in accordance with subsection b, below. A Sub-transmission customer shall normally be subject to the provisions of subsection a. If SCE approves a customer's request to have SCE implement the load reduction or if the customer does not comply with prior required load reductions, as specified in subsection c, the customer will be subject to the provisions of subsection b.

a. Customer-Implemented Load Reduction.

(i) Notification of Required Load Reduction. At the direction of the ISO, SCE shall notify each Sub-transmission customer in an affected rotating outage group to drop its entire load. Within 30 minutes of such notification, the customer must drop its entire load. The customer shall not return the dropped load to service until 90 minutes after SCE sent the notification to the customer to drop its load, unless SCE notifies the customer that it may return its load to service prior to the expiration of the 90 minutes.

(ii) Method of Notification. SCE will notify Sub-transmission customers who are required to implement their own load reduction via telephone, by either an automated calling system or a manual call to a business telephone number or cellular phone number designated by the customer. The designated telephone number will be used for the sole purpose of receiving SCE's rotating outage notification and must be available to receive the notification at all times. When SCE sends the notification to the designated telephone number the customer is responsible for dropping its entire load in accordance with subsection a. (i), above. The customer is responsible for informing SCE, in writing, of the telephone number and contact name for purposes of receiving the notification of a rotating outage.

(iii) Excess Energy Charges. If a Sub-transmission customer fails to drop its entire load within 30 minutes of notification by SCE, and/or fails to maintain the entire load drop until 90 minutes after the time notification was sent to the customer, unless SCE otherwise notified the customer that it may return its load to service earlier in accordance with subsection a. (i) above, SCE shall assess Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during the applicable rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage penalty period in hours. Excess Energy Charges will be determined and applied by SCE subsequent to the Sub-transmission customer's regularly scheduled meter read date following the applicable rotating outage. (L)

(L)

(Continued)

Schedule DBP — Sheet 8

DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

17. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

a. Customer-Implemented Load Reduction. (Continued) (L)

(iv) Authorized Residual Ancillary Load. Authorized Residual Ancillary Load is load that is deemed to be equivalent to five percent of the Sub-transmission customer's prior billing month's recorded Maximum Demand. This minimum load level is used as a proxy to allow for no-load transformer losses and/or load attributed to minimum grid parallel operation for generators connected under Rule 21.

b. SCE-Implemented Load Reduction.

Non-exempt Sub-transmission customers may request, in writing, to have SCE drop the customer's entire load during all applicable rotating outages using SCE's remote-controlled load drop equipment (control equipment). If SCE agrees to such arrangement, SCE will implement the load drop by using one of the following methods:

(i) Control Equipment Installed. For a Sub-transmission customer whose load can be dropped by SCE's existing control equipment, SCE will implement the load drop during a rotating outage applicable to the customer. The customer will not be subject to the Notification and Excess Energy Charge provisions set forth in subsection a, above.

(ii) Control Equipment Pending Installation. For a Sub-transmission customer whose load can not be dropped by SCE's existing control equipment, the customer must request the installation of such equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities. Pending the installation of the control equipment, the customer will be responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions. (L) (T)

c. Non-compliance: A non-exempt Sub-transmission customer subject to subsection a, above, who fails to drop load during three rotating outages in a three year period to a demand level of 20% or less of the customer's prior billing month's recorded Maximum Demand averaged over the applicable rotating outage period, is not in compliance with this tariff. The three year period shall commence with the first failure to drop load as specified in this subsection. A customer not in compliance with this condition will be placed at the top of the Sub-transmission customer rotating outage group list and will be expected to comply with subsequent applicable rotating outages. In addition, the customer must select one of the two options below within fifteen days after receiving written notice of non-compliance from SCE. A customer failing to make a selection within the specified time frame will be subject to subsection c.(ii) below.

(i) Subject to Schedule OBMC: The customer shall submit an OBMC Plan, in accordance with Schedule OBMC, within 30 calendar days of receiving written notice of non-compliance from SCE. Pending the submittal of the OBMC Plan by the customer and pending the review and acceptance of the OBMC Plan by SCE, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy charge provisions. If the customer fails to submit an OBMC Plan within 30 days of receiving notice of non-compliance from SCE, or if the customer's OBMC Plan is not approved by SCE, or if the customer fails to meet the requirements of Schedule OBMC once the OBMC Plan is approved, the customer shall be subject subsection c.(ii), below. (L)

(Continued)

Schedule DBP — Sheet 9

DEMAND BIDDING PROGRAM

(Continued)

SPECIAL CONDITIONS (Continued)

17. Customers with Service Metered and Delivered at Voltages above 50 kV (Sub-transmission customers) Included in Rotating Outages. (Continued)

c. Non-compliance: (Continued)

(L)

(ii) Installation of Control Equipment. The customer shall be subject to the installation of control equipment at the customer's expense in accordance with SCE's Rule 2, Section H, Added Facilities, if such equipment is not currently installed. If such switching capability is installed, SCE will drop the customer's load for all applicable subsequent rotating outages in accordance with the provisions of subsection b, above. Pending the installation of control equipment, the customer will remain responsible for dropping load in accordance with the provisions of subsection a, above, including the Notification and Excess Energy Charge provisions.

d. Net-Generators (N)

Sub-transmission customers who are also net-generators are normally exempt from rotating outages, but they must be net suppliers of power to the grid during all rotating outages. For the purpose of this Special Condition, a net-generator is an SCE customer who operates an electric generating facility as part of its industrial or commercial process, and the generating facility normally produces more electrical power than is consumed in the industrial or commercial process, with the excess power supplied to the grid. Sub-transmission customers whose primary business purpose is to generate power are not included in this Special Condition.

(i) Notification of Rotating Outages. SCE will notify sub-transmission customers who are net-generators of all rotating outages applicable to customers within SCE's service territory. Within 30 minutes of notification, the customer must ensure it is a net supplier of power to the grid throughout the entire rotating outage period. Failure to do so will result in the customer losing its exemption from rotating outages, and the customer will be subject to Excess Energy Charges, as provided below.

(ii) Excess Energy Charges. Net generators who are not net suppliers to the grid during each rotating outage period will be subject to Excess Energy Charges of $6 per kWh for all kWh usage in excess of the Authorized Residual Ancillary Load. Such charges will be based on the total kWh usage during a rotating outage penalty period, less the product of Authorized Residual Ancillary Load in kW and the applicable rotating outage period hours. Excess Energy Charges will be determined and applied by SCE subsequent to the customer's regularly scheduled meter read date following the applicable (N) rotating outage. Excess Energy Charges shall not apply during periods of (L) verifiable scheduled generator maintenance or if the customer's generator suffers a verifiable forced outage. The scheduled maintenance must be approved in advance by either the ISO or SCE, but approval may not be (T) unreasonably withheld. (L)

DEMAND BIDDING PROGRAM AT-A-GLANCE
PREVIOUS DBP VS. REVISED DBP

Old DBP	Revised DBP
• Commit to reduce the greater of 100 kW or 10% of the customer's maximum demand during a DBP event	• Have demands greater than 200 kW and commit to reduce at least 100 kW during a DBP event
• May concurrently participate in an Interruptible program (e.g., I-6, I-6-BIP or ACCP), or Optional Binding Mandatory Curtailment (OBMC) Program	• May concurrently participate in an Interruptible program (For example, I-6, I-6-BIP or ACCP) or Critical Peak Pricing (CPP)
• DBP event is triggered when the California Independent System Operator (CAISO) declares an Alert Notice, Warning, Stage 1, 2, or 3 Emergency	• A day-ahead DBP event is triggered when the SCE price offer exceeds $0.15 per kWh, for four consecutive hours, by 2:00 p.m. on a day-ahead basis. A day-of DBP event, or testing and evaluation of the program, is triggered when the CAISO declares a Warning, or Stage 1, 2, or 3 Emergency by 11:00 a.m. the same day
• Hourly incentive payment of $0.35 per kWh for each hour of power reduction	• Day-ahead incentive payment equal to the accepted price offer of $0.15 per kWh or greater. Day-of incentive payment of $0.50 per kWh of actual power reduction
• 10-Day Rolling Average using the average energy usage for the past 10 days	• 10-Day Rolling average using the average energy usage for the 3 highest days of the past 10 similar days
• Day-Ahead events could occur between the hours of 8 a.m. to 8 p.m. and Day-Of events could occur between 3 p.m. to 8 p.m.	• Day-Ahead event can occur between 12 p.m. to 8 p.m. and Day-Of events can occur between 3 p.m. to 8 p.m.
• Customers notified via SCE Energy Manager website along with courtesy notification via pagers and e-mail by 3 p.m. for Day-Ahead bidding and by Noon for Day-Of bidding	• Notification via customer's designated primary telephone number will start by 3 p.m. for Day-Ahead bidding and by Noon for Day-Of bidding
• Customers may log onto SCE Energy Manager and change their notification preferences	• Customers may elect to receive 'back-up' courtesy event notification via alphanumeric pager or cellular telephone, fax or e-mail but will no longer receive notification via SCE's EnergyManager website
	• A Technical Assistance Incentive of up to $50 per kW is available for professional technical assistance that enhances a customer's ability to respond to DBP events. Site visits and/or program surveys administered by the California Energy Commission (CEC) may be required

This is meant as an aid to understanding SCE's pricing schedules. It does not replace the tariffs. Please refer to the individual rate schedule of interest for a complete listing of terms and conditions of service, which can be viewed or printed via the Internet at ***www.sce.com*** *(Regulatory Info Center).*

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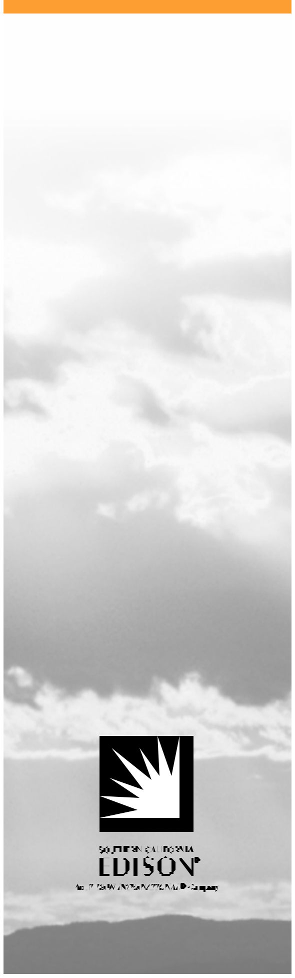
INFORMATION ABOUT SCE'S DEMAND BIDDING PROGRAM (DBP)

Receive credit for reducing electricity usage by participating in a web-based bidding program

The Demand Bidding Program (DBP) is a flexible Internet-based bidding program that offers Southern California Edison's (SCE) customers with demands greater than 200 kW, the opportunity to receive a credit on their bill for voluntarily reducing power without incurring any financial penalty. By participating in the program, customers can also assist in alleviating power shortages in California as well as reducing their overall power costs.



ELIGIBILITY

The DBP program is available to customers with demands greater than 200 kW, who rely on SCE for generation, transmission and distribution electric services (bundled service customers). These customers must not procure power from another provider (take Direct Access service). Participants are required to have an interval meter and Internet access.

Customers participating in the DBP program will be required to allow the California Energy Commission (CEC), or its contracting agent, to conduct a site visit for measurement and evaluation of the program and agree to complete any evaluation surveys needed to enhance the program.

GOOD CANDIDATES FOR DBP

Good candidates for the DBP might be large business, industrial, and agricultural customers with the flexibility of reducing at least 100 kW of electricity **not critical to** their main operations or processes on days when a DBP Event is activated, which could be from the hours of Noon to 8:00 p.m., Monday through Friday, excluding holidays.

FINANCIAL CREDIT FOR PARTICIPATION IN THE DBP

Day-Ahead participants may be eligible to receive a credit equal to $0.15 per kWh or greater, for reducing power during a Day-Ahead DBP Event. Day-Of participants may be eligible to receive $0.50 per kWh, for reducing power during a Day-Of DBP Event.

- **Day-Ahead Event (Price-Triggered):** SCE may activate a DBP Event on a "Day-Ahead" basis when the forecast of the next day's market price of power exceeds $0.15 per kWh for four consecutive hours between noon and 8:00 p.m.
- **Day-Of Event (Emergency-Triggered):** SCE may activate a DBP Event on a "Day-Of" basis, when the California Independent System Operator (CAISO) has declared a "Warning" or Stage 1, 2, or 3 System Emergency. A credit of $0.50 per kWh may apply to actual reduced power usage during a Day-Of DBP Event, calculated on an hourly basis during a DBP Event.
  In addition, a DBP Emergency Test Event may be activated by SCE without meeting the definition of an actual emergency, as defined above. Two

Emergency Test Events will occur each year, lasting no longer than four (4) hours each event. Participants must meet the same requirements as those of an actual DBP Event to receive a DBP credit during a DBP Day-Of Emergency Test Event. A participating customer may receive a credit of $0.50 per kWh of actual power reduction during a DBP Emergency Test Event.

BIDDING OPTIONS

The DBP offers "Day-Ahead" and "Day-Of" bidding options. A Day-Ahead Event may occur any weekday (excluding holidays) between the hours of Noon and 8:00 p.m. A Day-Of Event may occur between 3:00 p.m. and 8:00 p.m. Customers may vary their energy bid commitment by hour for each DBP Event. However, a customer must bid in at least two consecutive hours of an Event, and may place only one energy bid per Event Day, via SCE's **designated Internet website.** Credits will appear on customer bills after the meter has been read and DBP credits have been calculated.

HOW TO SUBMIT A COMMITMENT TO REDUCE POWER THROUGH THE WEBSITE

DBP participants must submit bid commitments to reduce power via the Internet, at SCE's EnergyManager Website. Customers will need a user ID and password to access the Website. Once SCE has received a signed DBP Agreement and Non-Disclosure Agreement, a logon user ID and password will be supplied for customer use in logging onto the Website. DBP participants may log on directly to the Website at https://www.sceenergymanager.com or type http://www.sce.com/drp to go to the Demand Bidding Program on the "Demand Response Programs" section of sce.com. Customers will be able to view the specific DBP Event period on which they will be bidding. For questions regarding the Website and how to bid, call **(626) 302-8320** or e-mail SCE at drp/sce/eix@sce.com.

- To place a "Day-Ahead" bid, customers will log onto the SCE EnergyManager Website between 3:00 p.m. and 4:00 p.m. the day before the event and place their kWh reduction bid for each hour of the DBP Event. If SCE does not designate a different time, the default period for a Day-Ahead Event will be from Noon to 8:00 p.m. Customers may log back onto the Website after 5:00 p.m. to see if their bid was accepted. If customers can "view" the event, then their bid was accepted.
- To place a "Day-Of" bid, log onto the SCE EnergyManager Website between Noon and 1:00 p.m. and place your kWh reduction bid for each hour of the DBP Event. The CAISO will determine the length of each event. If the CAISO does not designate the time, the default period for a Day-Of Event will be from 3:00 p.m. to 8:00 p.m. Log back onto the Website after 2:00 p.m. to see if your bid was accepted. If you can "view" the event, then your bid was accepted.

When will a customer become eligible to begin submitting commitments to reduce power?

Once a customer and an SCE representative sign the required DBP Agreement and Non-Disclosure Agreement and SCE determines the required metering equipment is installed, the Agreement becomes effective. You can then initiate service on the Website through the Internet. SCE will provide all participants with a logon ID and password.

CUSTOMER SPECIFIC ENERGY BASELINE (CSEB)

For SCE to determine how much energy each customer actually reduced during a DBP Event, we must know what the usage would have been before the customer reduced power; this is referred to as the "Customer Specific Energy Baseline" or the "CSEB."

SCE will use the "10-Day Rolling Average Energy Usage" methodology to calculate each customer's CSEB. The CSEB is determined on an hourly basis using the average energy usage for the three (3) highest total energy usage days out of the ten (10) days prior to a DBP Event excluding other DBP days or days the customer was paid to reduce power or days when a customer was subject to a rotating outage. The CSEB is then subtracted from the actual amount of kWh used for that hour during the DBP Event to determine the actual kWh reduction. The results of this calculation will determine if the customer complied with the program and the amount of the bill credit and other incentive the customer should receive.

How is the credit calculated?

The credit calculation is determined by measuring the difference between the customer's CSEB for each DBP hour and the customer's actual energy usage for that hour. Then, the actual energy reduction is multiplied by the specified price for that DBP Event for each hour of the event. DBP participants will receive a credit on their bill if they reduced at least 50 percent and up to 150 percent of their committed power reduction. These requirements are applicable each hour of a DBP Event.

What if customers do not reduce power to their committed reduction amount or reduce more or less than their "Committed Power Reduction" amount?

If a customer reduces less than 50 percent of their committed power reduction, the customer will not receive a credit during that hour. DBP participants are eligible for DBP credits for reductions from 50 percent up to 150 percent of their committed power reduction amount, but will not receive credits for any power reductions greater than 150 percent of their committed electricity amount. This threshold is measured each hour of a DBP Event.

What if a customer submits a commitment and does not reduce power during a DBP event?

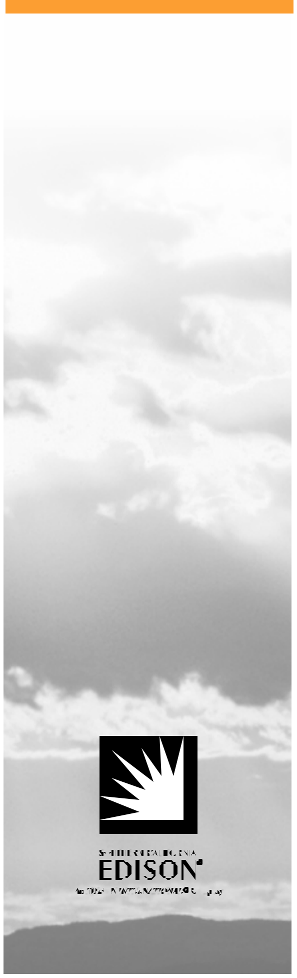
There are no penalties for submitting a commitment and not reducing power. However, this may have a negative effect if you participate on either the Bill Protection and/or Technical Assistance Incentive option.

TYPES OF EQUIPMENT NEEDED

Customers must have an SCE-approved interval metering system capable of recording usage in 15-minute intervals and Internet access to bid and receive status of DBP Events. Customers with multiple meters on the same or adjacent sites may choose to have one or all of their meters, each with demands greater than 100 kW, to participate in the DBP as long as at least one of the meters has a demand of at least above 200 kW. Customers will also need Internet access in order to submit their power reduction commitments. Contact your SCE representative for details on obtaining access to the Website, as well as information on the required interval metering system.

NOTIFICATION

SCE will notify customers of a DBP Event via their designated primary telephone number. SCE will begin notifying customers by 3:00 p.m. the day before a Day-Ahead Event and by 12:00 p.m. the day of a Day-Of Event. If SCE does not reach the customer, SCE will make two more attempts, directly following the first attempt, on the designated primary telephone number. SCE does not guarantee customer receipt of the notification. Participating customers will be responsible for all charges incurred during a DBP Event, even if the customer does not receive actual notice. Participants may also opt to receive courtesy notifications via pager, cellular



telephone, electronic mail, or by fax. All equipment needed to receive notifications is at the customer's expense.

TECHNICAL ASSISTANCE INCENTIVE

The Technical Assistance Incentive allows DBP participants the opportunity to earn a cash incentive for professional technical assistance that enhances their ability to respond to power reduction events. The cash incentive, up to $50 per kW, is broken into two parts. Participants will receive 50 percent, or up to $25 per kW, of the incentive for potential CPP power reduction, upon certification by a CEC-approved professional engineer.

To receive the remaining half of the Technical Assistance Incentive, customers will have to demonstrate that their actual power reduction is equal to at least 50 percent of their certified power reduction per DBP Event. A customer must participate in a minimum of two DBP Events, or tests, must be successfully completed before October 1, 2005. The Technical Assistance Incentive will be available to participants from July 1, 2003 and expires December 31, 2005 or until available funds are exhausted, whichever is sooner. If the minimum level of measured power reduction does not occur, DBP participants will not receive the remainder of the incentive.

The CEC also offers a free program called The Enhanced Automation Program. Customers may call 1-866-732-5591 or access via the Internet at www.ConsumerEnergyCenter.org/enhanced automation. This program may help customers become more knowledgeable about their potential for reducing power; however, to receive the first Technical Assistance Incentive, customers will still have to contact a CEC-certified engineering firm.

CONTRACTUAL REQUIREMENTS

An executed DBP Agreement is mandatory prior to participation in this program. You must also sign the applicable Non-Disclosure Agreement. Contact your SCE representative for a copy of the DBP Agreement and Non-Disclosure Agreement.

Q A **What other Demand Response Programs may a customer take part in while participating in the DBP?**

Other applicable Demand Response Programs include Interruptible programs (for example, I-6, I-6-BIP), Critical Peak Pricing (CPP), and the Scheduled Load Reduction Program (SLRP).

Q A **What happens when a DBP Event and a CPP Event, or the I-6 program, are activated at the same time?**

Customers will not be eligible for DBP credits during periods of overlap of a DBP and CPP Event. *The CPP or the I-6 program will take precedence over the DBP.*

Q A **What happens when the both DBP and the SLRP are activated at the same time?**

Customers will be eligible for credits under the DBP but will not be eligible for credits under the SLRP during periods of overlap of a DBP and SLRP Event. *The DBP program will take precedence over the SLRP.*

FOR MORE INFORMATION

SCE has several programs available to help customers better manage their electricity costs, including rebates, incentives, energy surveys, and payment options. For questions about SCE programs, call **(800) 990-7788.**

For more information about the Demand Bidding Program, call the DBP Hotline **(626) 302-8320,** contact your SCE representative, visit www.sce.com, or type www.sce.com/drp to go directly to the Demand Bidding Program.

This fact sheet is meant as an aid to understanding SCE's pricing schedules. It does not replace the tariffs. Please refer to the individual rate schedule of interest for a complete listing of terms and conditions of service, which can be viewed or printed via the Internet at ***www.sce.com*** *(Regulatory Info Center).*

EDISON

SDG&E

SCHEDULE DBP

DEMAND BIDDING PROGRAM

APPLICABILITY

The Demand Bidding Program (DBP) is a demand/energy bidding program that offers incentives to customers for reducing energy consumption and demand during specific DBP event periods described in the Special Conditions. This Schedule is applicable, in combination with the customer's otherwise applicable tariff(s), on a voluntary basis to all customers with demands greater than 200 kW and who can commit to reduce a minimum of at least 100 kW per hour during a DBP event period. Customers may not aggregate accounts to meet the minimum requirement for this program.

TERRITORY

Within the entire territory served by the Utility.

RATES

DBP Reliability Incentive: $0.50 per kWh of Actual Demand Reduction.
DBP Test Incentive: $0.50 per kWh of Actual Demand Reduction.
DBP Price Incentive: A per-kWh Price Offer will be issued for Actual Demand Reduction. The offer will at a minimum be in excess of $0.15 per kWh.

DBP Incentive Payment. Pursuant to the provisions of Special Condition 12, the DBP Incentive Payment for bundled customers is calculated by multiplying the customer's Actual Demand Reduction by the DBP Incentive for a customer's accepted bid for a Day-Of Reliability Bidding Event or a Day-Ahead Price Bidding Event.

D

The payment amount will be applied to the total charges of the customer's otherwise applicable rate schedule billing. The Utility will provide the DBP Incentive Payment as an adjustment to the customer's regular monthly bill, within 90 days of the DBP bidding event. The Utility will make DBP Incentive Payments only for those hours of Accepted Demand Reduction, as limited by Special Conditions 10 and 12.

SPECIAL CONDITIONS

1. Definitions. The definitions of terms used in this schedule are found either herein or in Rule 1.

2. Day-Ahead Price Demand Bidding Event. A Day-Ahead Price Demand Bidding Event occurs when the Utility issues a day-ahead hourly price forecast where the forecast price exceeds $0.15 per kWh for four consecutive hours between 12:00 p.m. noon and 8:00 p.m. The utility will issue an hourly price offer to the customer. Customers may submit a single Demand Bid per Day-Ahead Event, indicating the amount of kW curtailment they are offering and the specific timeframe for which they will curtail. Day-Ahead Events are limited to Monday through Friday, excluding holidays. There is no limit to the number of Day-Ahead Demand Bidding Events per month or per year.

(Continued)

SCHEDULE DBP

DEMAND BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

3. Day-Of Reliability Demand Bidding Event. A Day-Of Reliability Demand Bidding Event (Day-Of Event) occurs when the Utility activates an emergency event to offset outstanding system issues that may affect system reliability. The Utility may also activate an emergency event based upon notification from the ISO of an ISO Hour-Ahead Warning Notice or more advanced ISO Notice (Stage 1, 2 or 3 Emergency) after 2:00 p.m. on the day preceding the Day-Of Event and up to 11:00 a.m. on the day of the Day-Of Event, and the Utility requests bids from customers. Unless the ISO identifies a specific time period, the Day-Of Event shall be deemed to occur between 3:00 p.m. and 8:00 p.m. Customers may submit a single Demand Bid per Day-Of Event if the Customer has not already submitted a Demand Bid for a Day-Ahead Event to occur on that same day, indicating the amount of kW curtailment they are offering and the specific timeframe for which they will curtail within the specified time period. Day-Of Events are limited to Monday through Friday, excluding holidays. There is no limit to the number of Day-Of Events per month or per year. L T T

4. Demand Bid. A Demand Bid is the amount of kW per hour (kWh usage) that a customer commits to reduce for each hour of a Day-Ahead or Day-Of Event. For each hour of each Day-Ahead or Day-Of Event, the customer must submit the customer's Demand Bid for a minimum demand reduction not less than 100 kW per hour. Each bid must be for a minimum of 2 hours and each bid must be for consecutive hours during the Day-Ahead or Day-Of Event. Customers shall not submit a Day-Ahead and Day-Of Event Demand Bid for the same day. T

5. Bid Submission. Customers shall submit a Demand Bid via the Utility's designated Internet website. For Day-Ahead Events, participating customers shall submit bids to the website within one hour of notification of bid solicitation, but not later than 4:00 p.m. the day before the Day-Ahead Event. For Day-Of Events, participating customers shall submit bids to the website within one hour of receipt of notification of bid solicitation, but not later than 1:00 p.m. on the Day-Of Event. A customer Demand Bid may be submitted beyond one hour after notification of bid solicitation, but the Utility need not give equal consideration to late and timely bids. T

6. Bid Evaluation. Unless a capacity level (megawatt quantity) is specified in the ISO notification, the Utility will deem all qualified Demand Bids received by the deadline acceptable from Customers. In evaluating late bids, the Utility will consider then-current conditions, including previous acceptance or rejection of timely bids submitted within the first hour. Bidding shall be accepted for non-holiday weekdays only. Unless a capacity level (MW quantity) is specified in the ISO or Utility event notification, the Utility will then evaluate the qualified bids received based on a first come, first served basis, taking bidder past performance and compliance into account, and accept or reject each bid. If preliminary meter data indicates that a customer is not entitled to receive compensation for the prior three consecutive Day-Ahead or Day-Of Events, such customer will thereafter be precluded from participating in the following two operations of the DBP. L T T T

7. Bid Acceptance/Rejection Notification. The Utility will notify the customer of bid acceptances or rejections within one (1) hour after the bid submission deadline. Notification of bid acceptances or rejections will be sent via electronic mail (e-mail) no later than 5:00 p.m. on the day before the Day-Ahead Event, and no later than 2:00 p.m. on the day of a Day-Of Event. The Utility does not guarantee the reliability of the Internet site by which customers submit Demand Bids and receive information regarding this Schedule. Bid solicitations can be terminated prior to Acceptance Notification, up to the deadline (5:00 p.m. for Day-Ahead, 2:00 p.m. for Day-Of) based on ISO notification that load relief is no longer needed. L

(Continued)

SCHEDULE DBP

DEMAND BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

8. Expected Demand. Expected Demand (baseline) is the customer's average consumption for the three highest days for the same hour of the day over the immediately preceding 10 similar days prior to the Day-Ahead or Day-Of Event. The past 10 similar days will include the hours of 12 p.m. to 8 p.m. Monday through Friday, excluding holidays, and will additionally exclude days when the customer was paid to reduce load on Day-Ahead or Day-Of Event days, CPP event days, interruptible or other curtailment program operation days, or when rotating outages are called. Expected Demand is used to determine the customer's Actual Demand Reduction for each Day-Ahead or Day-Of Event.

9. Metering Requirement. Customer's electric meter must be an interval data recorder with related telecommunications capability, compatible with the Utility's meter reading and telecommunications systems. Metering equipment must be in operation for at least 10 similar days prior to participating in the program to establish a baseline. If required, the Utility will provide and install the metering equipment at no cost to the customer through December 31, 2004.

   The customer is responsible for the installation and monthly fees associated with telephone equipment and a dedicated line if such equipment is required for the remote reading or monitoring of the interval meter, unless these are provided under the terms of another program. Customers receiving an interval meter from the Utility pursuant to this rate schedule will be able to continue to use it at no additional cost even after the Program is terminated, provided that the customer remains in the Program continuously for a minimum period of one year, and submits and complies with a Demand Bid for the first ten (10) Day-Ahead and/or Day-Of Events, if bids are requested and the customer's bid is accepted.

   Non-compliance with a Day-Ahead or Day-Of Event occurs if the customer's Demand Bid is accepted by the Utility and the customer fails to satisfy the energy reduction requirement necessary to earn the DBP incentive. A customer who receives an interval meter through this Program but later elects to leave the Program prior to the one-year anniversary date, or does not bid and comply with 10 Day-Ahead and/or Day-Of Events, will reimburse the Utility for all expenses associated with the cost, installation and maintenance of the meter. Pursuant to Electric Rule 2, Section I, such charges will be collected as a one-time payment, and any failure to pay such charges will subject the customer to service termination pursuant to Electric Rule 11.E. If the customer would have received an interval meter at no charge as a result of another program, the customer will not be required to reimburse the Utility for these metering expenses.

D

10. Multiple Meters on Single Facility. When a customer has multiple meters serving a single facility, including meters that do not meet the kW demand threshold, a customer may request that all of the meters be served under the Schedule DBP, subject to the conditions herein. All of the meters must currently be on the AL-TOU or PA-T-1 rate schedules. At least one of the meters must have a billing demand equal to or exceeding 100 kW (in the case of AL-TOU) or 200 kW (in the case of PA-T-1). All of the accounts for the meters must have the same business or corporate entity listed as the customer name. The meters must all serve a single facility or premise. This definition may include a contiguous property that is not divided by any public right of way or property owned by another entity.

(Continued)

SCHEDULE DBP

DEMAND BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

11. Cancellation of Day-Ahead or Day-Of Event. In the case where the ISO cancels its Alert or Warning or more advanced ISO Notice (Stage 1, 2 or 3 Emergency), the Utility will reject any bid that has not yet been accepted. Once a customer's Demand Bid has been accepted, the accepted bid shall not subsequently be rejected by the Utility, but payment shall continue to be based on the customer's actual performance, as measured by the Actual Demand Reduction. T

12. Actual Demand Reduction. The Actual Demand Reduction equals the difference between the customer's hourly Expected Demand and the recorded hourly kWh consumption during a Day-Ahead or Day-Of Event. T

13. DBP Participation Payment. The DBP Incentive for each Demand Bidding Event will be calculated based on the customer's Actual Demand Reduction. Credits will only apply to the portion of the hourly Actual Demand Reduction that falls within a +/- 50 percent bandwidth of the customer's Demand Bid. In no case will a customer receive a credit payment for a given hour if it does not meet, in that hour of the Event, the minimum energy reduction threshold which shall not be less than 100 kW. T T T

14. Utility Testing. Customers are required to participate in no more than two (2) tests per year of the communications and responsiveness of customers to a Demand Bidding Request. During such a test the customer shall be responsible to curtail load consistent with the rest of the terms of this Rate Schedule. Test events shall be no longer than 4 hours. The incentive paid to participants shall be the product of their demand reduction and $0.50 per kWh per test event. T D T N

15. Contract Requirement For Service. As a condition precedent to commencing service on this Schedule, customer shall submit to the Utility a completed Demand Bidding Program Contract (Form 140-00100) and, if acceptable to the Utility, the Utility shall sign and return the Form Contract to customer. A customer may not commence service on this Rate Schedule until the Utility has signed and returned the Form Contract to the customer. T

Customers on this tariff must agree to allow the Utility, the California Energy Commission (CEC) or its contracting agent to conduct a site visit for measurement and evaluation, and agree to complete any surveys needed to evaluate the DBP program. Furthermore, customer shall provide all load data and background information, under appropriate confidentiality protections, needed to complete this evaluation. The data will also be made available to academic researchers, under appropriate confidentiality protections, to facilitate the understanding of demand response. N N

As a condition of accepting service on this tariff, any price offer proffered to the customer must remain confidential. T

16. Utility Reporting. Utility will provide the Commission with a monthly report on the economics of this Rate Schedule. The monthly report may contain information on individual customer performance. T

17. Termination of Schedule. Upon signing the Form Contract for Service on Schedule DBP, customer shall remain on the Rate Schedule until the Schedule is terminated or the Customer submits its termination in writing to the Utility. Customers may choose to terminate the Contract at any time. Contract termination shall be effective 5 days following Utility's receipt of customer's written termination. This Schedule is in effect until modified or terminated in the rate design phase of SDG&E's next general rate case or similar proceeding. T

(Continued)

SCHEDULE DBP

DEMAND BIDDING PROGRAM

SPECIAL CONDITIONS (Continued)

18. Form of DBP Communications. The Utility will notify the customer of Demand Bid Acceptance or Rejection by e-mail, and/or other communication means specified by the Utility. Customer shall be responsible for the cost and maintenance to receive such communications and to send Demand Bids via the Internet. The Utility does not guarantee the reliability of the Internet site or e-mail system used for such communications.

19. Multiple Program Participation. A customer may participate in the DBP while taking service under Schedule EECC-CPP, Critical Peak Pricing (CPP). Customers currently taking service under Schedule AL-TOU-CP, Base Interruptible Program (BIP), Scheduled Load Reduction Program (SLRP), Rolling Blackout Reduction Program (RBRP) or Optional Binding Mandatory Curtailment (OMBC) are eligible to receive service under this schedule. However, under no circumstances will a customer taking service under the above listed rate schedules and this schedule receive more than one incentive payment for the same interrupted/curtailed load. For the duration of this schedule, customers enrolled in this program shall not participate in the California Power Authority Demand Reserves Program. T | | | T L L T T

20. Failure to Reduce Energy. Except as provided in Special Condition 9 of this Schedule, no additional financial penalties will be assessed under this Schedule for a customer's failure to comply or participate during a Day-Ahead or Day-Of Demand Bidding Event.

21. Emergency Standby Generation Limitations. Customers may achieve energy reductions by operating back-up or onsite generation. The customer will be solely responsible for meeting all environmental and other regulatory requirements for the operation of such generation. Not withstanding all other applicable SDG&E Rules and Tariffs, Customer may synchronize and operate its own standby generation in parallel with the electric system up to 60 cycles to minimize service interruption during the transfer of electric service between the Utility electric system and the Customer's Emergency Standby Generation, such operation shall only occur during the period starting 15 minutes prior to and ending 15 minutes after a Day-Ahead or Day-Of Event defined in this Schedule. Customer must receive approval of their interconnection plans from Utility prior to operation of their generator in parallel with Utility's system. In no Event shall the customer operate its own standby generation in parallel with the Utility electric system during Utility service interruptions.

    Upon termination or expiration of the term of this Schedule or associated Form Contract, customer agrees to either 1) dismantle all equipment necessary for customer's own standby generation to synchronize and operate in parallel with the Utility electric system for the purpose of electric service transfer from the Utility electric system to the customer's own standby generation, or 2) purchase and install a generator output meter meeting Utility's standards and either comply with applicable tariffs or take service under a contract.

22. Technical Assistance Incentive. The technical assistance option shall enable customers to earn a rebate for professional technical assistance that enhances the customer's ability to respond to curtailment requests for on-peak demand reductions. Customers shall receive a rebate (not to exceed actual costs) based on $50 per kW of curtailable on-peak load reduction nominated by the customer through a signed Technical Assistance Incentive Application.

(Continued)

22. Technical Assistance Incentive. (Continued)

Customer shall receive 50% of the rebate following submission of a signed Application prepared in conjunction with an audit conducted by a CEC-certified Professional Engineer (P.E.) of potential on-peak load reductions. Customers shall receive the remainder of the rebate after demonstrating peak demand reduction of at least 50% of their nominated load drop as averaged over all DBP events or tests. If the minimum level of demand reduction does not occur, the customer shall not be awarded the remainder of the rebate. A minimum of two (2) DBP events or tests must be successfully completed to calculate the average performance level and award the incentive.

The technical assistance incentives will be available to participants until December 31, 2005, or until the funding for the transitional incentives are exhausted.

Participants receiving a technical assistance incentive under the Critical Peak Pricing Program (Schedule EECC-CPP) are ineligible to receive a technical assistance incentive for the same consulting study under this schedule.

D

DEMAND BIDDING PROGRAM CONTRACT

This Contract is made and entered into by and between the following parties:

San Diego Gas & Electric Company, a California corporation, hereinafter referred to as "SDG&E" and ________________________________ hereinafter referred to as “Customer”, and jointly, or individually, referred to as "Parties" or "Party".

I. RECITALS

WHEREAS, Customer is herein requesting to take service on Schedule DBP, Demand Bidding Program on a voluntary basis without penalty.

NOW, THEREFORE, THE PARTIES AGREE AS FOLLOWS:

II. TERM

This Contract shall become effective when signed by both parties. The effective date of the Contract shall be the last date signed by a party. This Contract shall remain effective unless terminated sooner by the terms herein.

III. DEMAND REDUCTION BID

Customer shall voluntarily provide Demand Bids consistent with the meaning of that term on Schedule DBP included herein by reference.

IV. AVERAGE ANNUAL DEMAND

Average Annual Demand is equal to Customer’s total kWh consumption for the previous 12 months, divided by 8760.

V. ASSIGNMENT

Customer shall not assign this Contract without prior written consent of SDG&E.

VI. DISPUTE RESOLUTION

Any dispute that cannot be resolved between the Parties shall be settled by means of conference, mediation, arbitration and/or litigation as provided for herein.

The first step in the dispute resolution process shall be a conference by which the dispute is referred to a designated officer of each party for resolution. If those two officers cannot reach an agreement within a reasonable period of time, the parties shall submit the dispute to mediation.

The second step in the dispute resolution process shall be mediation between the parties in accordance with the Commercial Rules of the American Arbitration Association. If the dispute is not resolved by the mediation, the parties shall submit the dispute to arbitration or litigation. Should the parties not agree on arbitration, either party may seek remedy in the Superior Court of the County of San Diego, California.

In any action in litigation to enforce or interpret any of the terms of this Contract, the prevailing party shall be entitled to recover from the unsuccessful party all costs, expenses, (including expert testimony) and reasonable attorneys fees (including fees and disbursements of in-house and outside counsel) incurred therein by the prevailing party.

VII. DISCLAIMER OF WARRANTY

No promise, representation, warranty, or covenant not included in this Contract has been, or is relied on by either Party. Each Party has relied on its own examination of this Contract, the counsel of its own advisors, and the warranties, representations, and covenants in the Contract itself.

VIII. LIMITATION OF LIABILITY

The limitations of liability set forth below in this Section VII shall not apply to errors or omissions caused by willful misconduct, fraudulent conduct, or violations of law.

In no event shall SDG&E, its shareholders, directors, employees, agents or subcontractors (including, without limitation, suppliers of the System) (collectively, the "SDG&E Parties") be liable to Customer for any direct, indirect, consequential, special, incidental, or punitive damages under any other theories including, but not limited to, tort, contract, breach of warranty or strict liability for the design, manufacture, installation, operation, maintenance, performance or demonstration of the System. The System includes any metering, meter communications equipment, Internet communication software, energy demand management software and related goods and services. SDG&E shall not be responsible for any business loss, actual or implied, as a result of the partial or complete failure of the communications systems to operate.

IX. COMPLIANCE WITH LAWS

The parties shall comply with the terms and conditions of the DBP tariff, attached hereto as Attachment C and incorporated herein by reference, and all, local, state and federal rules, regulations and laws.

X. COMMISSION CONTINUING AUTHORITY

This Contract shall at all times be subject to the Commission and to any changes or modification that the Commission may, from time to time, direct in the exercise of its jurisdiction.

Notwithstanding any other provision of this Contract, either Party shall have the right to unilaterally file with the Commission, pursuant to the Commission's rules and regulations, an application for a change in rates, charges, classification, or any rule, regulation, or agreement relating thereto.

IN WITNESS WHEREOF, SDG&E and Customer have executed this Contract:

Customer______________________	San Diego Gas & Electric Company
By ______________________	By ______________________
Title ______________________	Title ______________________
Date ______________________	Date ______________________

Included by attachment are:
Customer Contact Information
Customer Account Information
Schedule DBP
Non-Disclosure Agreement
Non-Disclosure Certificate

ATTACHMENT A
Demand Bidding Program
Customer Contact Information

Primary Contact:
Name: ____
Title: ____
Mailing Address: ____
____
Telephone Number: ____
Pager Number: ____
Email Address: ____

Secondary Contact:
Name: ____
Title: ____
Mailing Address: ____
____
Telephone Number: ____
Pager Number: ____
Email Address: ____

Additional Contact:
Name: ____
Title: ____
Mailing Address: ____
____
Telephone Number: ____
Pager Number: ____
Email Address: ____

Additional Contact:
Name: ____
Title: ____
Mailing Address: ____
____
Telephone Number: ____
Pager Number: ____
Email Address: ____

Attach additional Customer Account Information sheets to this contract if required. (Sheet ____ of _____)

ATTACHMENT B
Demand Bidding Program
Customer Account Information

Site #1
Account Name ________________________________
Account Number ________________________________
Site Address ________________________________
Existing Electric Meter Number ________________________________
Customer Committed Load Reduction ________________________________

Site #2
Account Name ________________________________
Account Number ________________________________
Site Address ________________________________
Existing Electric Meter Number ________________________________
Customer Committed Load Reduction ________________________________

Site #3
Account Name ________________________________
Account Number ________________________________
Site Address ________________________________
Existing Electric Meter Number ________________________________
Customer Committed Load Reduction ________________________________

Site #4
Account Name ________________________________
Account Number ________________________________
Site Address ________________________________
Existing Electric Meter Number ________________________________
Customer Committed Load Reduction ________________________________

Site #5
Account Name ________________________________
Account Number ________________________________
Site Address ________________________________
Existing Electric Meter Number ________________________________
Customer Committed Load Reduction ________________________________

ATTACHMENT C
Demand Bidding Program
Schedule DBP

ATTACHMENT D
(For Schedule DBP Applicants Only)

NON-DISCLOSURE AGREEMENT REGARDING CONFIDENTIALITY OF CERTAIN SAN DIEGO GAS AND ELECTRIC COMPANY PRICE DATA

This Non-Disclosure Agreement (Agreement) is entered into between San Diego Gas and Electric Company (SDG&E), a California Corporation, and ______________________________ (Customer).

1. This Agreement shall govern access to and the use by Customer of all SDG&E power price forecast data ("Protected Data" as more fully defined herein) provided to Customer in connection with Customer's participation in SDG&E's Demand Bidding Program (DBP). Notwithstanding any termination of the DBP, this Protective Order shall remain in effect until it is specifically modified or terminated by SDG&E.

   (a) The term "Protected Data" means the day-ahead forecast of SDG&E's hourly power prices and/or price offer provided to Customer as part of Customer's participation in the DBP. Protected Data includes all copies of the hourly power prices, and all notes or analyses incorporating, containing, or derived from the hourly power prices. Protected Data includes, but is not limited to, information created, stored, or transmitted in electronic form.

   (b) Protected Materials shall not include: (i) any information or document contained in the public files of the California Public Utilities Commission (CPUC) or any other state or federal agency, or in any state or federal court, unless such information or document has been determined to be protected by such agency or court; or (ii) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Agreement.

   (c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto as Attachment E by which persons who have been granted access by Customer to the Protected Data shall, as a condition of such access, certify their understanding that such access is provided pursuant to the terms and restrictions of this Agreement, and that such persons have read such Agreement and agree to be bound by it. All Non-Disclosure Certificates shall be retained by Customer and made available to SDG&E upon request.

   (d) A Reviewing Representative shall mean any person, including any employee or consultant of Customer, who is engaged in activities (including the direct supervision of a person so engaged) relating to advising Customer or preparing Customer in connection with Customer's participation in the DBP and who is not a Market Participation Representative as defined below.

   (e) A Market Participation Representative shall include any person, including any employee or consultant of Customer, who is engaged in activities (including the direct supervision of a person so engaged), for Customer or others, relating to the purchase, sale or marketing of energy or capacity, or the bidding on or purchasing of power plants or consulting on such matters, but shall explicitly exclude the activities of advising customers on utility rates, Direct Access transactions, and/or demand response programs.

2. Access of Reviewing Representatives to Protected Data shall be granted only pursuant to the terms of this Agreement. Any person who is a Market Participation Representative shall not be granted access to Protected Data.

3. Within thirty (30) days after receiving Protected Data, Customer shall return or destroy the Protected Data. Upon request by SDG&E, an officer of customer shall also submit to SDG&E an

affidavit stating that, to the best of declarant's knowledge, all Protected Data have been returned or destroyed. To the extent Protected Data is not returned or destroyed pursuant to this paragraph, it shall remain subject to this Agreement.

4. In the event Customer receives a request from a state or federal governmental agency or via a judicial subpoena for the production of the Protected Data in Customer's possession, the Customer will immediately notify SDG&E of such request. Customer and SDG&E shall cooperate in opposing the request or requiring the continued confidential treatment of the requested data by the requesting agency.

5. Protected Data shall be treated as confidential by Customer and each Reviewing Representative in accordance with the certificate executed pursuant to Paragraph 2(c) hereof. Protected Materials shall not be used except as necessary for the purpose of assisting in Customer's effective participation in the DBP and shall not be disclosed in any manner to any person except other Reviewing Representatives who are engaged in Customer's participation in DBP and who need to know the information in order to carry out their responsibilities.

6 In the event that a Reviewing Representative to whom Protected Data is disclosed ceases to be engaged in activities concerning SDG&E's DBP, access to Protected Data by that person shall be terminated. Even if no longer engaged in such reviews, every such person shall continue to be bound by the provisions of this Agreement and the Non-Disclosure Certificate. No Reviewing Representative may engage in any activities which would define him or her as a Market Participation Representative for a period of 30 days after ceasing his or her Reviewing Representative duties. Customer agrees to use best efforts to inform SDG&E immediately, in writing, if Customer becomes aware that a former Reviewing Representative has engaged in Market Participation Representative activities sooner than 30 days after ceasing his or her Reviewing Representative activities.

7 All disputes arising under this Agreement shall be presented for resolution to the CPUC in the first instance. Prior to presenting any such dispute to the CPUC, the parties to the dispute shall use their best efforts to resolve it informally. Neither SDG&E nor the Customer waives its right to seek additional administrative or judicial remedies in the event the CPUC acts or declines to act regarding the dispute.

8. Neither SDG&E nor Customer waives its right to pursue any other legal or equitable remedy that may be available in the event of actual or anticipated disclosure of Protected Data.

9. SDG&E and Customer may agree at any time to remove the "Protected Data" designation from any material if, in their mutual opinion, its confidentiality is no longer required.

10. SDG&E shall not be liable to Customer for any liability or damage, of any kind, incurred or sustained by Customer, including for claims against Customer by third parties, as a result of use by Customer of the Protected Data.

11 This Agreement shall be governed by and interpreted in accordance with the laws of the State of California.

12. This Agreement contains the entire understanding between the parties with respect to the Protected Data. No change or modification shall be made effective unless in writing and signed by an authorized representative of each party.

13. This Agreement is subject to change or modification by the CPUC.

IN WITNESS WHEREOF, the parties have executed this Agreement by their authorized representatives as of the date set forth above.

SAN DIEGO GAS AND ELECTRIC COMPANY		**CUSTOMER**	
By:	______________________ Signature	By:	______________________ Signature
	______________________ Print		______________________ Print
	______________________ Title		______________________ Title
	______________________ Date		______________________ Date

ATTACHMENT E
(For Schedule DBP Applicants Only)

NON-DISCLOSURE CERTIFICATE

I, ________________________________(individual's name), have been retained or designated by ________________________________(Customer) to review certain materials that have been designated as "Protected Data" under the terms of the **NON-DISCLOSURE AGREEMENT REGARDING CONFIDENTIALITY OF CERTAIN SAN DIEGO GAS AND ELECTRIC COMPANY PRICE DATA** entered into between ________________________________ (Customer) and San Diego Gas and Electric Company on __________________(date). (the Agreement).

1. I hereby certify my understanding that access to Protected Data is provided to me pursuant to the terms and restrictions of the Agreement, that I have been given a copy of and have read the Agreement, and that I agree to be bound by it. I understand that the Protected Data, any notes or other memoranda, or any other form of information that copies or discloses Protected Data shall not be disclosed to anyone other than in accordance with the Agreement. I acknowledge that a violation of the terms of the Agreement also constitutes a violation of an order of the California Public Utilities Commission.

2. I understand that my review of Protected Data is solely for the purpose of assisting Customer in participating in SDG&E's Demand Bidding Program, and that any other use or disclosure of Protected Data by me is a violation of the Agreement.

Dated: ____________________________

BY: ____________________________

TITLE: ____________________________

Technical Assistance Incentive Application

For Utility Use Only	
Date Received :	
Date of First Payment/Amount:	
Date of Second Payment/Amount:	
Date of Non-Compliance Notification:	

Date: ____________________

CUSTOMER INFORMATION

Company Name: ____________________

Name As It Appears On Your Utility Bill: ____________________

Contact Name: ____________________

Address: ____________________

City: ____________________ Zip: ____________________

Phone: ____________ Fax: ____________ Email: ____________________

Tax Status: (check one)
- ☐ Individual/Sole Prop.
- ☐ Corporation
- ☐ Partnership
- ☐ Exempt

Participating In:
- ☐ Critical Peak Pricing (CPP) Program
- ☐ Demand Bidding Program (DBP)
- ☐ Hourly Pricing Option (HPO)

SITE INFORMATION

Site Name: ____________________

Address: ____________________

City: ____________________ Zip: ____________________

Site Contact Name: ____________________ Contact Phone #: ____________________

Elec. Service Acct. or ID: ____________________

Facility Type: ____________________
(Office, Hospital, etc.)

Facility Area: ____________ Facility Age: ____________ Number of Floors: ______

INCENTIVE PAYMENT INFORMATION

Incentive check should be made payable and sent to the following:
(checks CANNOT be made payable to a non-related third party)

Company Name: ____________________

Mailing Address: ____________________

City: ____________________ State: ____________ ZIP: ____________

Telephone Number: ____________________ Fax Number: ____________________

Fed Tax ID Number: ____________________

TECHNICAL ASSISTANCE REPORT

Engineer Firm : ____________________

Date of Report: ____________________

Signature: ____________________

Print Name: ____________________

P.E. License Number: ____________________

P.E. Certification Stamp

Technical Assistance Incentive Application

TECHNICAL ASSISTANCE REPORT (continued)

Description of all measures recommended in report by Professional Technical Assistance Engineering Firm (Use second sheet if necessary)

Project Description	Type (Lighting/AC/ Motors/Others)	Total Measures Cost	Projected kW Reduction	Check (X) if Measure will be Implemented to Achieve Demand Response Commitment
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
		$	kW	
			Total kW identified in the study	Total kW of items check [a]
			kW	kW

Incentive based on Projected kW Reduction [b]: $ ____________

(kW demand reduction [a] x $50.00)

Cost for Professional Technical Assistance Report [c]: $ ____________

Estimated Professional Technical Assistance Incentive: $ ____________

(Incentive amount equal to the lesser of [b] or [c])

Technical Assistance Incentive Application

Customer Acknowledgements

I, ___________________________, on behalf of _____________________________________ (name of company), hereby acknowledge the following:

__________________________ (name of company) (hence forth referred to as the "Customer") has entered into a contract with a Professional Technical Assistance Engineer, who is on the California Energy Commission's (CEC) approved list of engineering firms, for professional technical advice regarding the installation of new equipment or modification of existing equipment or behavior at the Project Site listed on the front of this application (the Project). Of the recommendations that were presented in Customer's report from the Professional Technical Assistance Engineer, the Customer has implemented the measures that are listed to achieve the Customer's committed demand reduction for the Critical Peak Pricing Program, Demand Bidding Program, and/or Hourly Pricing Option (SDG&E only) Program, that the Customer is participating in. The Customer understands that they may not increase the amount of certified load reduction identified by the engineering firm; however, the Customer may choose a lesser amount and is ultimately responsible for the load reduction stated on this application.

The Customer understands that the Technical Assistance Incentive of $50 per kW of potential curtailable on-peak load, up to 100% of the study cost, applies to the cost of the study only by the CEC-approved engineer, and not for the installation of permanent equipment. The Customer understands that the Technical Assistance Incentive will be paid in two parts. The first part of the incentive ($25 per kW up to 50% of study cost) will be paid after the Utility receives this completed application; a copy of the study by the CEC-approved engineer; and a copy of a paid invoice. The second part of the incentive ($25 per kW up to 50% of study cost) will be paid after the customer meets the compliance criteria (for performance in the first four consecutive summer months for the CPP/HPO program or after the first two DBP events or tests in which the customer reduces load within program guidelines) as stated in the applicable tariff. The measurement and evaluation of compliance for the second part of the incentive will commence on the date that the check is issued for the first part of the incentive. Customers who fail to meet the criteria of the second part of the incentive will not receive the remainder of the payment. Incentive payments will be paid out on a first-come, first-served basis upon Customer's completion of all requirements. No Technical Assistance Incentives will be paid beyond December 31, 2005, or after the California Public Utilities Commission approved incentive funds are depleted, whichever comes first.

The Customer has signed an Authorization to Receive Customer Information or Act on a Customer's Behalf Form that grants the CEC, or its agent, the ability to gather energy data directly from the Customer's electric meter, or through the Utility's designated Internet site.

The Customer agrees that the Utility Administrator will have no role in resolving any disputes between the Professional Technical Assistance Engineer and the Company.

The Customer understands that as a condition of being on the Program, inspections and measurements of the performance of the Measures installed may be required. Therefore, the Customer agrees to provide access to the Project Site for these purposes to the CEC, the Utility Administrator, or its contracting agent, during the Customer's participation in a demand response program.

The Customer has authority to contract, on behalf of the legal owners of the Project Site, for installation of the Measures, or the Customer has obtained the permission of the legal owner of the Project Site to install the Demand Response Measures under the Customer's contract with the Professional Technical Assistance Engineer.

The Customer agrees to release the Utility Administrator, its affiliates, subsidiaries, parent company, officers, managers, directors, agents, and employees from all claims, demands, losses, damages, costs, expenses, and liability (legal, contractual, or otherwise), which arise from or are in any way connected with any: (1) injury to or death of persons, including but not limited to employees of the Utility Administrator, Customer, or Professional Technical Assistance Engineer; (2) injury to property or other interests of the Utility Administrator, Customer, Professional Technical Assistance Engineer, or any third party; (3) violation of local, state, or federal common law, statute, or regulation, including but not limited to environmental laws or regulations; (4) energy savings shortfall; so long as such injury, violation, or shortfall (as set forth in (1) - (4) above) arises from or is in any way connected with the Project, including Professional Technical Assistance Engineer's performance of or failure to perform the Project, however caused, regardless of any strict liability or negligence of the Utility Administrator, its officers, managers, or employees.

The Customer understands that the Utility Administrator has made no warranty or representation regarding the qualifications of the Professional Technical Assistance Engineer, and that we are solely responsible for the selection of the Professional Technical Assistance Engineer to implement the Project. The Customer understands that the Professional Technical Assistance Engineer is an independent engineer and is not authorized to make any representations on the behalf of the Utility Administrator.

Customer Signature: ______________________________ Date: ______________

Customer Name (Please Print): ______________________________

——— PLEASE MAKE A COPY OF THIS DOCUMENT FOR YOUR RECORDS ———

APPENDIX C
STATEWIDE CPP AND DBP MATERIALS

CRITICAL PEAK PRICING

The Critical Peak Pricing (CPP) rate offers lower rates to customers who agree to reduce electricity during critical peak periods during the summer season only.

DEMAND BIDDING PROGRAM

The Demand Bidding Program (DBP) is a no-risk program whereby participants earn bill credits for reducing their power usage when contacted.

BASE INTERRUPTIBLE PROGRAM

The Base Interruptible Program (BIP) offers a monthly bill credit to businesses that commit to reducing power to a minimum pre-determined level when requested.

OPTIONAL BINDING MANDATORY CURTAILMENT

The Optional Binding Mandatory Curtailment (OBMC) program exempts businesses from rolling blackouts/rotating outages in exchange for reducing power on their circuit during an electricity shortage.

SCHEDULED LOAD REDUCTION PROGRAM

The Scheduled Load Reduction Program (SLRP) offers bill credits to businesses that commit to reducing their power by a set amount on pre-determined days from June 1—September 30 regardless of whether there is an electricity shortage.

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CRITICAL PEAK PRICING

The Critical Peak Pricing (CPP) rate offers lower rates to customers who agree to reduce electricity during critical peak periods during the summer season only.

CPP At-A-Glance

Program Requirement	Reduction Required	Reward	Notification Lead Time	Participation	Risk
Monthly maximum demand >200 kW (>100 kW: SDG&E)	None	Lower rates on non-CPP days	Day-Ahead	12 days per summer season	Higher on-peak energy charges on CPP days

Features and Benefits

- Lower energy charges on non-critical peak period days.
- Day-Ahead notification provides flexibility for operational planning.
- Summertime-only commitment minimizes operational impact.
- Easy to manage using your utility's Internet-based Energy Management tool.
- Technical Assistance Incentives are available to qualified participants.
- Bill protection is available to qualified participants. Contact your local utility for more information.

Who is eligible to participate?

Businesses with monthly maximum demands of 200 kW or greater (100 kW for SDG&E) who purchase their electric commodity from their local utility. Customers with special billing or metering arrangements may not qualify. Contact your local utility for more information. Other eligibility requirements may apply.

Who are prime candidates for this program?

Customers who can reduce or shift loads during designated critical peak periods.

How does the program work?

Participating customers are notified on a Day-Ahead basis of a CPP event day and will receive a rate discount in exchange for higher prices on 12 CPP events days. Customers are encouraged to reduce or shift load to lower priced non-CPP hours.

Can customers participate in other demand response programs?

Participants may be eligible to participate in other demand response programs, but restrictions apply. Participants cannot receive incentives from more than one program for the same load reduction. Contact your local utility for more information.

For more details on Critical Peak Pricing, contact your Account Representative or local utility:

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DEMAND BIDDING PROGRAM

The Demand Bidding Program (DBP) is a no-risk program whereby participants earn bill credits for reducing their power usage when contacted.

DBP At-A-Glance

Program Requirement	Reduction Required	Reward	Notification Lead Time	Participation	Risk
Participation in reduction bidding	100 kW	Financial: starting at $0.15/kWh; System Emergency: $0.50/kWh	Financial: Day-Ahead; Emergency: Day-Of	Voluntary	None

Features and Benefits

- Participation is purely voluntary. There is no financial penalty associated with this program.
- Financial incentives can help reduce your bill and offset other costs.
- Easy to manage using your utility's Internet-based Energy Management tool.
- Participation helps the community by reducing the likelihood of rolling blackouts/rotating outages.
- Flexible load reduction amounts and time periods.
- Technical Assistance Incentives are available to qualified participants.

Who is eligible to participate?

Businesses that purchase their electric commodity from their local utility and who can reduce their electric load by a minimum of 100 kW with Day-Ahead or Day-Of notification.

Approximately how much electricity is a 100 kW load?

- 700 four-lamp fluorescent lighting fixtures (like those typically found in offices)
- 130 horsepower of motor load
- 400 personal computers

How does the program work?

On a Day-Ahead or Day-Of basis, participants will be notified that a bidding session will be forthcoming. Participants will "bid" (a) the amount of electric load they can reduce, and (b) the hours at which they are willing to reduce this load. The minimum bid is 100 kW per participating meter and can vary from hour to hour within a single event. A minimum of two consecutive hours is required for a bid.

Bidding occurs Monday through Friday, excluding holidays, and is not dependent on a declared emergency situation. Day-Ahead events will be called between noon and 8 pm. Participants will be notified of (or can verify) the status of their bid by 5pm the day before the event.

For a Day-Of event, participants will be contacted the day of to reduce load.

How is the incentive calculated?

Incentives are based on comparing load and usage for the same hours using the three highest usage days from the ten previous days. For an incentive to be paid, a minimum reduction of 100 kW per hour is required.

Can customers participate in other demand response programs?

Participants may be eligible to participate in other demand response programs, but restrictions apply. Participants cannot receive incentives from more than one program for the same load reduction. Contact your local utility for more information.

For more details on Demand Bidding, contact your Account Representative or local utility:

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1.800.468.4743
inter-act@pge.com

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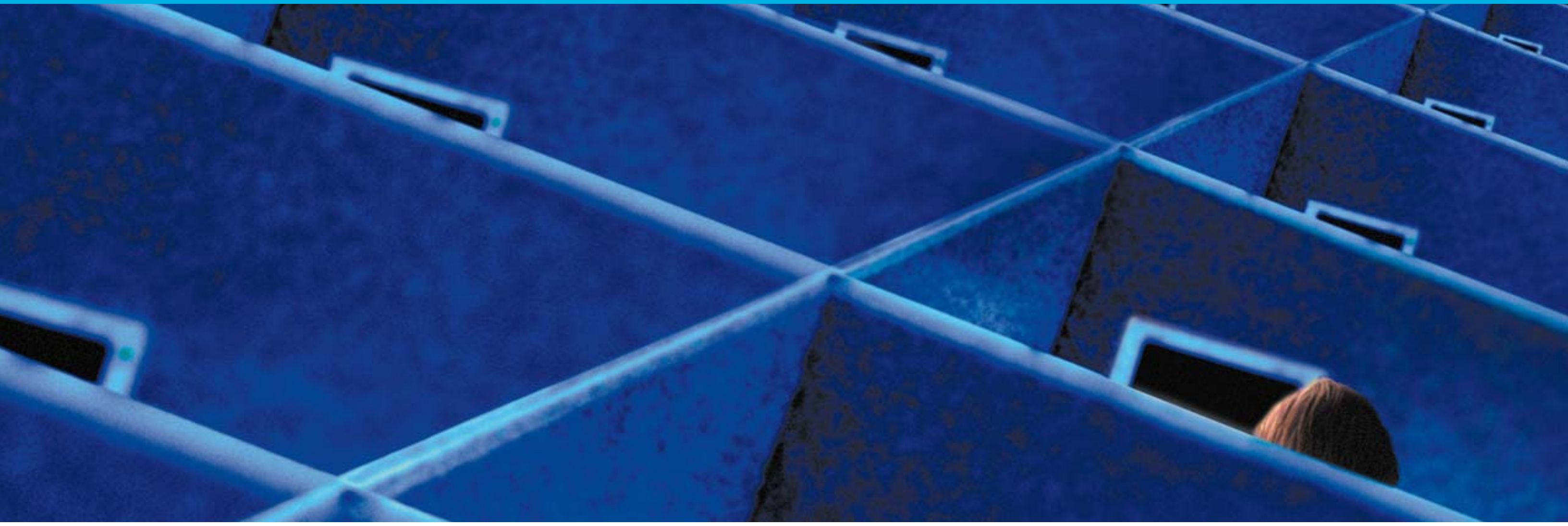

BASE INTERRUPTIBLE PROGRAM

The Base Interruptible Program (BIP) offers a monthly bill credit to businesses that commit to reducing power to a minimum pre-determined level when requested.

BIP At-A-Glance

Program Requirement	Reduction Required	Reward	Notification Lead Time	Participation	Risk
Commitment to pre-determined reduction level (Firm Service Level)	Higher of 100 kW or 15%	$7/kW monthly bill credit	30 minutes	Binding	$6/kWh on usage above Firm Service Level

Features and Benefits

- Receive a monthly "capacity" bill credit of $7/kW—even if no load reduction needed.
- Load reduction is required only during emergency situations.
- Easy to manage using your utility's Internet-based Energy Management tool.

Who is eligible to participate?

Businesses that can reduce electric load by at least 15% of their monthly average peak demand or a minimum of 100 kilowatts (kW), whichever is greater.

Approximately how much electricity is a 100 kW load?

- 700 four-lamp fluorescent lighting fixtures (like those typically found in offices)
- 130 horsepower of motor load
- 400 personal computers

What are the benefits of participation?

Participants in the BIP will receive a monthly bill credit of $7/kW per month for potential load reduction.

How does the program work?

When electric supplies are low, the California Independent System Operator will direct the utilities to call participants for load reductions. Program participants are required to have e-mail, Internet access, a dedicated telephone line, and/or an alphanumeric pager to receive these requests. Within 30 minutes of event notification, customers must reduce load to their designated Firm Service Level. Calls for load reduction under the BIP will not exceed four hours on any day, or ten calls per calendar month, or 120 hours per calendar year. Please contact your local utility representative for details.

To measure load reduction, your local utility will supply and install upgraded metering equipment if not already in place.

Are there penalties for not achieving the required load reductions?

There is a $6/kWh penalty for excess energy usage. During a curtailment event, excess energy is any energy used above the customer's Firm Service Level.

Can customers participate in other demand response programs?

Participants may be eligible to participate in other demand response programs, but restrictions apply. Participants cannot receive incentives from more than one program for the same load reduction. Contact your local utility for more information.

For more details on the Base Interruptible Program, contact your Account Representative or local utility:

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OPTIONAL BINDING MANDATORY CURTAILMENT

The Optional Binding Mandatory Curtailment (OBMC) program exempts businesses from rolling blackouts/rotating outages in exchange for reducing power on their circuit during an electricity shortage.

OBMC At-A-Glance

Program Requirement	Reduction Required	Reward	Notification Lead Time	Participation	Risk
Commitment to last-minute reduction	5-15% of circuit load	Exemption from rolling blackouts/ rotating outages	15 minutes	Binding	$6/kWh for energy consumed above power reduction commitment

Features and Benefits

- Exempts your business from rolling blackouts/rotating outages.
- Eliminates the hassle of work rescheduling/restocking, overtime charges, and loss of perishables.
- Ensures that other businesses on your circuit will not face power outages.
- Easy to manage using your utility's Internet-based Energy Management tool.

Who is eligible to participate?

Businesses that can commit to shedding up to 15% of their circuit are eligible. Reduction when requested is mandatory. Responsibility for load reduction on a circuit may be shared.

What are the benefits of participating?

OBMC participants are exempt from rolling blackouts/rotating outages. However, OBMC does not guarantee exemption from outages that occur as a result of other emergencies.

Who are prime candidates for this program?

In particular, businesses with production lines sensitive to power disruptions, those dealing in perishable commodities, or those with labor-intensive processes that face overtime costs may benefit most from the OBMC program.

How does the program work?

OBMC participants will be required to reduce load every time a rolling blackout/rotating outage occurs. If your business is the only business on your circuit, you alone are responsible for achieving the required load reduction level.

If you share a circuit with other businesses, your utility may assist with coordinating load reduction — the joint effort of customers on the same circuit to achieve the required electricity load reduction. If you are on a circuit requiring aggregate load reduction, one business on your circuit will be designated as the primary participant, and will be responsible for developing a plan for how load will be curtailed to achieve the required load reduction for your circuit. Please contact your local utility representative for details.

What happens when blackouts occur?

If rolling blackouts/rotating outages become necessary, your utility will initiate the curtailment signal at the direction of the California Independent System Operator. You will be notified through alphanumeric paging, dedicated phone line, and/or an Internet-based communication system. You will have 15 minutes from when the primary program participant receives notification to reduce load.

Are there penalties for not achieving the required reduction?

There is a $6/kWh penalty for energy consumed above the power reduction commitment.

Can customers participate in other demand response programs?

Participants may be eligible to participate in other demand response programs, but restrictions apply. Participants cannot receive incentives from more than one program for the same load reduction. Contact your local utility for more information.

For more details on Optional Binding Mandatory Curtailment, contact your Account Representative or local utility:

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SCHEDULED LOAD REDUCTION PROGRAM

The Scheduled Load Reduction Program (SLRP) offers bill credits to businesses that commit to reducing their power by a set amount on pre-determined days from June 1—September 30 regardless of whether there is an electricity shortage.

SLRP At-A-Glance

Program Requirement	Reduction Required	Reward	Notification Lead Time	Participation	Risk
Commitment to scheduled reduction	Higher of 100 kW or 15%	$0.10/kWh bill credit for load reduction	Pre-scheduled from June 1 to Sept 30	Binding	Removal from program after 5 failures to curtail

Features and Benefits

- Participation window limited to four-hour blocks in the summer period only.
- Pre-scheduling load reductions lets you plan necessary adjustments to business operations.
- Financial load reduction incentives can help reduce your bill and offset other costs.
- Easy to manage using your utility's Internet-based Energy Management tool.

Who is eligible to participate?

Businesses that purchase their commodity from their local utility who can reduce electric load by at least 15% of their average annual demand or a minimum reduction of 100 kilowatts (kW), whichever is greater.

Approximately how much electricity is a 100 kW load?

- 700 four-lamp fluorescent lighting fixtures (like those typically found in offices)
- 130 horsepower of motor load
- 400 personal computers

How does the program work?

Businesses are required to reduce load during the periods they choose (up to three periods can be selected, Monday through Friday) between June 1 and September 30. The program enrollment is for one year (January through December) and will be reviewed each November for the following year.

How is the incentive calculated?

Incentives are based on comparing load and usage for the same hours during the ten previous days. For an incentive to be paid, a minimum reduction of 100 kW or 15% of load is required. Compliance is measured on an hourly basis, and incentives will only be paid if the full curtailment commitment for the event is met.

Are there penalties for not achieving the required load reductions?

There is no financial penalty for not reducing load; however, participants can be removed from the program for five failures to curtail during the event season. In addition, monthly incentives will be lost if load shifting to the on-peak period occurs.

Can customers participate in other demand response programs?

Participants may be eligible to participate in other demand response programs, but restrictions apply. Participants cannot receive incentives from more than one program for the same load reduction. Contact your local utility for more information.

For more details on Scheduled Load Reduction, contact your Account Representative or local utility:

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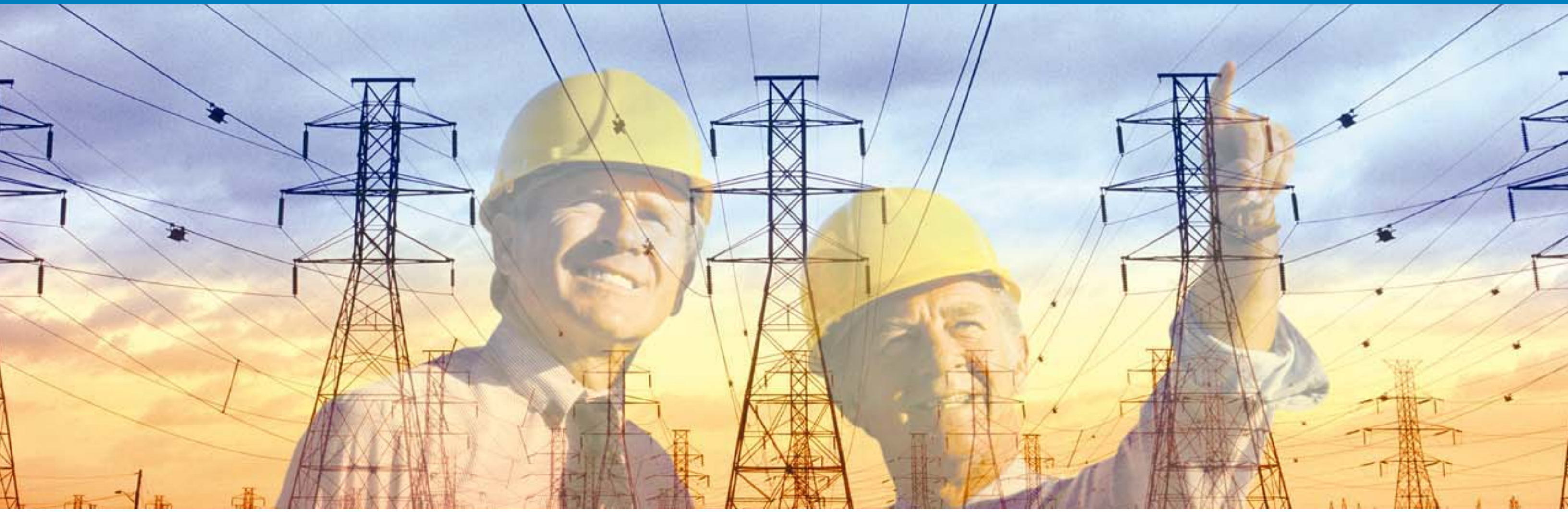

DEMAND RESPONSE TRANSITIONAL INCENTIVES

Transitional Incentives are designed to help you identify load reduction potential and provide financial assistance for the evaluation of demand response technologies such as automated controls to help facilitate participation in statewide Demand Response initiatives.

Enhanced Automation

If you need technical assistance to help you decide to make a commitment to participate in the California statewide Demand Response initiatives, the Enhanced Automation program is a great place to start. The California Energy Commission (CEC) has combined forces with Kema-Xenergy and Nexant to provide a free preliminary evaluation to identify demand response potential at your facility.

- Evaluations can be over the telephone, a half-day or full day on-site consultation
- Contact Kema-Xenergy at 1-866-732-5591 or enhancedautomation@xenergy.com

For more information about the Enhanced Automation program, visit the CEC website at: *www.ConsumerEnergyCenter.org/enhancedautomation*

Technical Assistance Incentive

If you believe you have load reduction potential at your facility but are unsure of how to reduce or how much you can reduce, contact one of the CEC-approved engineering firms for technical assistance.

The engineering firm you select will provide a detailed report that will explain how much load you can reduce and how you can accomplish this reduction with minimal impact to your business. The report will also provide the estimated cost to implement automated controls or other measures to facilitate quick and easy implementation of your load reduction strategy.

The cost for this professional audit is reimbursable, up to $50/kW of load reduction, provided you agree to participate in one of the eligible Demand Response initiatives. Currently, Critical Peak Pricing and Demand Bidding participants are eligible. SDG&E customers participating in the Hourly Pricing Option are also eligible.

For more information about Technical Assistance and participating engineering firms, visit the CEC website at: *www.energy.ca.gov*.

Bill Protection

If you decide to participate in one of the Demand Response rate initiatives, Critical Peak Pricing and SDG&E's Hourly Pricing Option, your cost will be protected for the first 14 months of your participation.

Bill Protection allows you to actively participate on a rate, and at the end of the first 14 months your costs will be evaluated. If the rate was not beneficial, you will not be charged for a rate higher than your otherwise applicable, or default rate. In other words, you will not pay more than you would have if you had not participated at all.

For more information on Bill Protection, please contact your local utility.

For more details on Transitional Incentives, contact your local utility:

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APPENDIX D
POST-EVENT / FINAL EVALUATION SURVEY INSTRUMENT

APPENDIX D
POST-EVENT / FINAL EVALUATION CUSTOMER SURVEY INSTRUMENT

INTRODUCTION

SCREEN1

[WHEN RECEPTIONIST ANSWERS]:
May I speak with [Customer Contact], please?

LEAD IN
INTRO1

Hello, this is ________________________, calling from Quantum Consulting on behalf of [UTILITY] and the California Public Utilities Commission. We are conducting a follow-up survey to determine how different businesses have responded to initial [Program: CPP, DBP or CPP/DBP] summer events. Are you the correct person to speak with regarding your organization's participation in the recent [UTILITY] [PROGRAM: CPP, DBP or CPP/DBP] event(s)?

[IF NEEDED:] This is a fact-finding survey only – we are NOT selling anything, and responses will not be connected with your firm in any way.

1	Yes	INTRO3
2	Respondent not available now	CALL BACK
3	Respondent coming to phone	INTRO2_1
4	No such person	INTRO1A
88	Refused	INTRO1A

INTRO1A
[IF NO SUCH PERSON]: May I speak with the person in your organization who is responsible for decisions regarding demand reductions associated with [PROGRAM: CPP, DBP or CPP/DBP] at your facility?

INTRO1B NAME OF CONTACT: ____________________________________
INTRO1C TITLE: ____________________________________

IF RESPONDENT IS NOT AVAILABLE, GET HIS/HER NAME AND TITLE; MAKE ARRANGEMENTS TO CALL LATER

INTRO2_1

WHEN RESPONDENT GETS ON THE LINE: Hello, this is ________________________, calling from Quantum Consulting on behalf of the California Public Utilities Commission and [UTILITY]. We are conducting the final evaluation survey for the 2004 [Program] program. Are you the correct person to speak with regarding your organization's participation in the [PROGRAM] program?

1	Yes	INTRO3
2	No	INTRO2A

INTRO2A

Who would be the best person in your organization to speak with about energy-related decisions for this facility? ____________________________________ ASK TO BE CONNECTED WITH THIS INDIVIDUAL.

INTRO2B

May I please speak with ___(insert from Intro2A)____________________

(IF CONTACT COMES TO PHONE, ASK INTRO2_1)
(IF CONTACT NOT AVAILABLE, SCHEDULE CALLBACK)

INTRO3

As part of a CPUC-sponsored evaluation of current demand response programs, we are speaking with all organizations to learn about their recent experiences in [UTILITY]'s [PROGRAM] program. The feedback you provide will be used by [UTILITY] and the CPUC to help improve the Demand Response offerings available to California energy users.

[IF NEEDED:] The information you provide will be kept in strictest confidence and used only for purposes of this program evaluation. If you agree to participate in the survey, [UTILITY] will provide energy use and load information for your facility to the research contractor. This information and your survey responses will be shared with the study team (the Energy Commission and its contractors, and [UTILITY]) only in a form that does not allow the identification of any business, individual or facility.

This interview should take about 15 minutes. Is this a good time for you or is there a better time I can call you back?

1	Yes	SC1
2	No, schedule callback	Call back
88	Refused	T&T

If utility contact information requested, please use the following:

SCE:	Edward Lovelace	(626) 302-1697
PG&E:	Susan McNicoll	(415) 973-7404
SDG&E:	Leslie Willoughby	(858) 654-1262

SC1. First, what is your job title? [DON'T READ]

1	Facilities Manager	SC2
2	Energy Manager	SC2
3	Other facilities management/maintenance position	SC2
4	Chief Financial Officer	SC2
5	Other financial/administrative position	SC2
6	Proprietor/Owner	SC2
7	President/CEO	SC2
8	Plant Manager	SC2
9	Controller	SC2
10	Engineer	SC2
11	Operations	SC2
77	Other (Specify)	SC2
88	Refused	SC2

99	Don't Know	SC2

SC2. [UTILITY] has provided us information indicating that your organization is currently signed up to participate in the [PROGRAM:CPP, DBP or CPP and DBP] program. Is this correct?

1	Yes ONLY [PROGRAM]	SC3
2	No, signed up for DBP	SC3
3	No, signed up for CPP	SC3
4	No, signed up for CPP and DBP	SC3
5	No, not signed up for either CPP or DBP	T&T
88	Refused	T&T
99	Don't Know	T&T

[(IF CPP = 1 and SC2=1) or SC2 in (3,4) then ask SC3, else skip to SC4]

SC3. Are you responsible for multiple facilities in the [UTILITY] service territory that are signed up for CPP?

1	Yes	SC3QTY
2	No	SC4
77	Other	SC4
88	Refused	SC4
99	Don't Know	SC4

SC3QTY. How many facilities, that you are responsible for, are signed up for CPP?

77	Enter #	SC4
888	Refused	SC4
999	Don't Know	SC4

[IF (DBP = 1 and SC2=1) or SC2 in (2,4) then ask SC4]

SC4. Are you responsible for multiple facilities in the [UTILITY] service territory that are signed up for DBP?

1	Yes	SC4QTY
2	No	CPP1_A
77	Other	CPP1_A
88	Refused	CPP1_A
99	Don't Know	CPP1_A

SC4QTY. How many facilities, that you are responsible for, are signed up for DBP?

77	Enter #	CPP1_A
88	Refused	CPP1_A
99	Don't Know	CPP1_A

CPP ACTIONS TAKEN / NOT TAKEN

[IF CEV1 = 1 and (CPP=1 and SC2(1) or SC2(3|4)) THEN READ:
"According to our records [UTILITY] has called CPP recent events on:

- [CPPEVENT1]
- [CPPEVENT2]
- [CPPEVENT3]"

and ASK CPP1_A]

CPP1_A. Did you take any demand reduction actions in response to the CPP event on [CPPEVENT1] ?

1	Yes	CPP1_B
2	No	CPP1_C
88	Refused	CPP2_A
99	Don't Know	CPP2_A

[IF CPP1_A=1 and SC3=1 then ask CPP1_B]

CPP1_B. At which facilities?

1	FAC_1	CPP2_A
2	FAC_2	CPP2_A
3	FAC_3	CPP2_A
4	FAC_4	CPP2_A
5	FAC_5	CPP2_A
6	ALL Facilities	CPP2_A
77	Other	CPP2_A
88	Refused	CPP2_A
99	Don't Know	CPP2_A

CPP1_C. Why didn't your firm take any demand reduction? [DO NOT READ Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	CPP2_A
2	Don't need to take action to save money	CPP2_A
3	Could not respond that fast	CPP2_A
77	Other	CPP2_A
88	Refused	CPP2_A
99	Don't Know	CPP2_A

[IF CEV2 = 1 and (^SC2(2) or SC2 in (3|4))]

CPP2_A. Did you take any demand reduction actions in response to the CPP event on [CPPEVENT2] ?

1	Yes	CPP2_B
2	No	CPP2_C
88	Refused	CPP3_A
99	Don't Know	CPP3_A

[IF CPP2_A=1 and SC3=1 then ask CPP2_B]

CPP2_B. At which facilities?

1	FAC_1	CPP3_A
2	FAC_2	CPP3_A
3	FAC_3	CPP3_A
4	FAC_4	CPP3_A
5	FAC_5	CPP3_A

6	ALL Facilities	CPP3_A
7	Same Facilities as First CPP Event	CPP3_A
77	Other	CPP3_A
88	Refused	CPP3_A
99	Don't Know	CPP3_A

CPP2_C. Why didn't your firm take any demand reduction? (Do Not Read)

1	Operation was already was shut down	CPP3_A
2	Don't need to take action to save money	CPP3_A
3	Could not respond that fast	CPP3_A
4	Same Reasons as First CPP Event	CPP3_A
77	Other	CPP3_A
88	Refused	CPP3_A
99	Don't Know	CPP3_A

[IF CEV3 = 1 and (^SC2(2) or SC2 in (3|4))]

CPP3_A. Did you take any demand reduction actions in response to the CPP event on [CPPEVENT3] ?

1	Yes	CPP3_B
2	No	CPP3_C
88	Refused	CPP4A
99	Don't Know	CPP4A

[IF CPP3_A=1 and SC3=1 then ask CPP3_B]

CPP3_B. At which facilities?

1	FAC_1	CPP4A
2	FAC_2	CPP4A
3	FAC_3	CPP4A
4	FAC_4	CPP4A
5	FAC_5	CPP4A
6	ALL Facilities	CPP4A
7	Same Facilities as Event 1	CPP4A
8	Same Facilities as Event 2	CPP4A
77	Other	CPP4A
88	Refused	CPP4A
99	Don't Know	CPP4A

CPP3_C. Why didn't your firm take any demand reduction? (Do Not Read)

1	Operation was already was shut down	CPP4A
2	Don't need to take action to save money	CPP4A
3	Could not respond that fast	CPP4A
4	Same Reasons as First CPP Event	CPP4A
5	Same Reasons as Second CPP Event	CPP4A
77	Other	CPP4A
88	Refused	CPP4A
99	Don't Know	CPP4A

[If CPP = 1 and (^SC2(2) or SC2(3|4)]

CPP4A. How likely are you to take demand reduction actions for future CPP events? (Can select 1-5 and 77)

1	Very Likely	CPP4B
2	Somewhat Likely	CPP4B
3	Neither Likely nor unlikely	CPP4B
4	Somewhat unlikely	CPP4B
5	Not at all Likely	CPP4B
77	Other	CPP4B
88	Refused	CPP4B
99	Don't Know	CPP4B

CPP4B. Is there anything that [Utility] can do to help you take Demand Reduction actions for future CPP events?

77	<RECORD VERBATIM>	DBP1_A
88	Refused	DBP1_A
99	Don't Know	DBP1_A

DBP ACTIONS TAKEN / NOT TAKEN

[IF BEV1 = 1 and (DBP=1 and SC2(1) or SC2(2|4)) THEN READ:

"According to our records [UTILITY] has called recent DBP events on:

- [DBPEVENT1]
- [DBPEVENT2]
- [DBPEVENT3]"

and ASK DBP1_A]

[IF BID1 = 0 (BID1 = 1 means they were NOT allowed to bid for the DBP event{PG&E})]

DBP1_A. Did you place a bid for the <DBPEVENT1> event?

1	Yes	DBP1_B
2	No	DBP1_C
88	Refused	DBP2_A
99	Don't Know	DBP2_A

[IF DBP1_A=1 and SC4=1 then ask DBP1_B]

DBP1_B. At which facilities?

1	FAC_1	DBP1_D
2	FAC_2	DBP1_D
3	FAC_3	DBP1_D
4	FAC_4	DBP1_D
5	FAC_5	DBP1_D
6	ALL Facilities	DBP1_D
7	Same Facility as CPP Program	DBP1_D
77	Other	DBP1_D
88	Refused	DBP1_D
99	Don't Know	DBP1_D

DBP1_C. Why didn't your firm place a bid for the <DBPEVENT1> event? [DO NOT READ: Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DBP2_A
2	Don't need to take action to save money	DBP2_A
3	Could not respond that fast	DBP2_A
4	Not available to bid that hour	DBP2_A
5	Never planning to bid for any event	DBP2_A
6	Could not reduce load on that particular day	DBP2_A
7	System Issue /No password	DBP2_A
77	<RECORD VERBATIM>	DBP2_A
88	Refused	DBP2_A
99	Don't Know	DBP2_A

[IF DBP1_A=2 or 88 or 99 READ: "Even though you didn't bid on this event…."]

DBP1_D Did you take any demand reduction actions at any of your facilities for the <DBPEVENT1> event?

1	Yes	DBP1_D2
2	No	DBP1_E
88	Refused	DBP2_A
99	Don't Know	DBP2_A

[IF DBP1_D = 1 and SC4=1 and (BID1=1 or DBP1_A in 2,88,99)]

DBP1_D2. At which facilities?

1	FAC_1	DBP1_F
2	FAC_2	DBP1_F
3	FAC_3	DBP1_F
4	FAC_4	DBP1_F
5	FAC_5	DBP1_F
6	ALL Facilities	DBP1_F
7	Same Facility as CPP Program	DBP1_F
77	Other	DBP1_F
88	Refused	DBP1_F
99	Don't Know	DBP1_F

[IF DBP1_D=2]

DBP1_E. Was there a reason you did not take any demand reduction actions for this event?
[DO NOT READ: Probe for complete answer – i.e. if they say they weren't notified find out was it because the page didn't go through or because they didn't have their pager on them at the time?]

1	Operation was already was shut down	DBP2_A
2	Don't need to take action to save money	DBP2_A
3	Could not respond that fast	DBP2_A
4	Not avail to bid that hour	DBP2_A
5	Never planning to bid for any event	DBP2_A
6	Could not reduce load on that particular day	DBP2_A
7	System Issue /No password	DBP2_A
8	Do not remember why	DBP2_A

9	Was not a mandatory reduction	DBP2_A
77	<RECORD VERBATIM>	DBP2_A
88	Refused	DBP2_A
99	Don't Know	DBP2_A

[IF BID1= 0 and DBP1_D = 1 and DBP1_A = 1]

DBP1_F. How did your actual reduction compare to the demand reduction you bid?

1	Reduction was close to what was bid	DBP2_A
2	Reduction was much LESS THAN what was bid	DBP1_G
3	Reduction was much MORE THAN what was bid	DBP1_G
77	<RECORD VERBATIM>	DBP2_A
88	Refused	DBP2_A
99	Don't Know	DBP2_A

[IF DBP1_F in (2,3)]

DBP1_G. Why was this? (Do Not Read)

1	Because my business allowed me to do it	DBP2_A
77	<RECORD VERBATIM>	DBP2_A
88	Refused	DBP2_A
99	Don't Know	DBP2_A

[IF BEV2 = 1 and BID2 = 0 and (DBP==1 and SC2(1) or SC2(2|4)]

[BID2 = 1 means they were NOT allowed to bid for the DBP event{PG&E}]

DBP2_A. Did you place a bid for the <DBPEVENT2> event?

1	Yes	DBP2_B
2	No	DBP2_C
88	Refused	DBP3_A
99	Don't Know	DBP3_A

[IF DBP2_A=1 and SC4=1 then ask DBP2_B]

DBP2_B. At which facilities?

1	FAC_1	DBP2_D
2	FAC_2	DBP2_D
3	FAC_3	DBP2_D
4	FAC_4	DBP2_D
5	FAC_5	DBP2_D
6	ALL Facilities	DBP2_D
7	Same Facility as DBP Event 1	DBP2_D
77	Other	DBP2_D
88	Refused	DBP2_D
99	Don't Know	DBP2_D

[IF DBP2_A=2]

DBP2_C. Why didn't your firm place a bid for the <DBPEVENT2> event?

1	Operation was already was shut down	DBP3_A

2	Don’t need to take action to save money	DBP3_A
3	Could not respond that fast	DBP3_A
4	Not avail to bid that hour	DBP3_A
5	Never planning to bid	DBP3_A
6	Could not reduce load on that particular day	DBP3_A
7	System Issue /No password	DBP3_A
8	Same reasons as on first bid	DBP3_A
77	<RECORD VERBATIM>	DBP3_A
88	Refused	DBP3_A
99	Don’t Know	DBP3_A

[IF DBP2_A=2 or 88 or 99 READ: “Even though you didn’t bid on this event….”]

DBP2_D Did you take any demand reduction actions at any of your facilities for the <DBPEVENT2> event?

1	Yes	DBP2_D2
2	No	DBP2_E
88	Refused	DBP3_A
99	Don’t Know	DBP3_A

[IF DBP2_D = 1 and SC4=1 and (BID2=1 or DBP2_A in (2, 88, 99)]

DBP2_D2. At which facilities?

1	FAC_1	DBP2_F
2	FAC_2	DBP2_F
3	FAC_3	DBP2_F
4	FAC_4	DBP2_F
5	FAC_5	DBP2_F
6	ALL Facilities	DBP2_F
7	Same Facilities as Event 1	DBP2_F
77	Other	DBP2_F
88	Refused	DBP2_F
99	Don’t Know	DBP2_F

[IF DBP2_D=2]

DBP2_E. Was there a reason you did not take any demand reduction actions for this event? (DO NOT READ)

1	Operation was already was shut down	DBP2_A
2	Don’t need to take action to save money	DBP2_A
3	Could not respond that fast	DBP2_A
4	Not available to bid that hour	DBP2_A
5	Never planning to bid for any event	DBP2_A
6	Could not reduce load on that particular day	DBP2_A
7	System Issue /No password	DBP2_A
8	Do not remember why	DBP2_A
9	Was not a mandatory reduction	DBP2_A
10	Same Reason as for DBP Event 1	DBP3_A
77	<RECORD VERBATIM>	DBP3_A
88	Refused	DBP3_A
99	Don’t Know	DBP3_A

[IF BID2= 0 and DBP2_D = 1 and DBP2_A = 1]

DBP2_F. How did your actual reduction compare to the demand reduction you bid?

1	Reduction was close to what was bid	DBP3_A
2	Reduction was much LESS THAN what was bid	DBP2_G
3	Reduction was much MORE THAN what was bid	DBP2_G
77	<RECORD VERBATIM>	DBP3_A
88	Refused	DBP3_A
99	Don't Know	DBP3_A

[IF DBP2_F in (2,3)]

DBP2_G. Why was this?

77	<RECORD VERBATIM>	DBP3_A
88	Refused	DBP3_A
99	Don't Know	DBP3_A

[IF BEV3 = 1 and BID3 = 0 and (DBP=1 and SC2=1 or SC2(2|4))]

[BID3 = 1 means they were NOT allowed to bid for the DBP event{PG&E}]

DBP3_A. Did you place a bid for the <DBPEVENT3> event?

1	Yes	DBP3_B
2	No	DBP3_C
88	Refused	DBP5A
99	Don't Know	DBP5A

[IF DBP3_A=1 and SC4=1 then ask DBP3_B]

DBP3_B. At which facilities?

1	FAC_1	DBP3_D
2	FAC_2	DBP3_D
3	FAC_3	DBP3_D
4	FAC_4	DBP3_D
5	FAC_5	DBP3_D
6	ALL Facilities	DBP3_D
7	Same Facility as DBP Event 1	DBP3_D
8	Same Facility as DBP Event 2	DBP3_D
77	Other	DBP3_D
88	Refused	DBP3_D
99	Don't Know	DBP3_D

[IF DBP3_A=2]

DBP3_C. Why didn't your firm place a bid for the <DBPEVENT3> event? (Do not read)

1	Operation was already was shut down	DBP5A
2	Don't need to take action to save money	DBP5A
3	Could not respond that fast	DBP5A
4	Not available to bid that hour	DBP5A
5	Never planning to bid for any event	DBP5A
6	Could not reduce load on that particular day	DBP5A

7	System Issue /No password	DBP5A
8	Same Reason as for DBP Event 1	DBP5A
9	Same Reason as for DBP Event 2	DBP5A
77	<RECORD VERBATIM>	DBP5A
88	Refused	DBP5A
99	Don't Know	DBP5A

[IF DBP3_A=2 or 88 or 99 READ: "Even though you didn't bid on this event…."]

DBP3_D. Did you take any demand reduction actions at any of your facilities for the <DBPEVENT3> event?

1	Yes	DBP3_D2
2	No	DBP3_E
88	Refused	DBP5A
99	Don't Know	DBP5A

[IF BID3=1 and DBP3_D = 1]

DBP3_D2. At which facilities?

1	FAC_1	DBP3_F
2	FAC_2	DBP3_F
3	FAC_3	DBP3_F
4	FAC_4	DBP3_F
5	FAC_5	DBP3_F
6	ALL Facilities	DBP3_F
7	Same Facilities as Event 1	DBP3_F
8	Same Facilities as Event 2	DBP3_F
77	Other	DBP3_F
88	Refused	DBP3_F
99	Don't Know	DBP3_F

[IF DBP3_D=2]

DBP3_E. Was there a reason you did not take any demand reduction actions for this event? (Do Not Read)

1	Operation was already was shut down	DBP2_A
2	Don't need to take action to save money	DBP2_A
3	Could not respond that fast	DBP2_A
4	Not available to bid that hour	DBP2_A
5	Never planning to bid	DBP2_A
6	Could not reduce load on that particular day	DBP2_A
7	System Issue /No password	DBP2_A
8	Do not remember why	DBP2_A
9	Was not a mandatory reduction	DBP2_A
10	Same Reason as for DBP Event 1	DBP5A
11	Same Reason as for DBP Event 2	DBP5A
77	<RECORD VERBATIM>	DBP5A
88	Refused	DBP5A
99	Don't Know	DBP5A

[IF BID3= 0 and DBP3_D = 1 and DBP3_A = 1]

DBP3_F. How did your actual reduction compare to the demand reduction you bid?

1	Reduction was close to what was bid	DBP5A
2	Reduction was much LESS THAN what was bid	DBP3_G
3	Reduction was much MORE THAN what was bid	DBP3_G
77	<RECORD VERBATIM>	DBP5A
88	Refused	DBP5A
99	Don't Know	DBP5A

[IF DBP3_F in (2,3)]

DBP3_G. Why was this?

1	Same Reason as for DBP Event 1	DBP5A
2	Same Reason as for DBP Event 2	DBP5A
77	<RECORD VERBATIM>	DBP5A
88	Refused	DBP5A
99	Don't Know	DBP5A

[IF (DBP=1 or SC2(2|4)]

DBP5A. What is the likelihood that you will place bids for future DBP events? Would you say you are ….. (Can select 1-5 and 77)

1	Very Likely	DBP5B
2	Somewhat Likely	DBP5B
3	Neither Likely nor unlikely	DBP5B
4	Somewhat unlikely	DBP5B
5	Not at all Likely	DBP5B
77	Reasons	DBP5B
88	Refused	DBP5B
99	Don't Know	DBP5B

DBP5B. Is there anything that [Utility] can do to help you bid on future DBP events?

77	<RECORD VERBATIM>	EV10
88	Refused	EV10
99	Don't Know	EV10

[IF CPP1_A(1) or CPP2_A(1) or CPP3_A(1) or DBP1_D(1) or DBP2_D(1) or DBP3_D(1)]

EV10. What demand reduction actions did you take in response to the most recent event in which you participated?

1	Used backup generators	EV10a
2	Allowed the temperature to rise in the occupied space	EV10a
3	Reduced overhead lighting	EV10a
4	Reduced or shut off some or all production processes	EV10a
5	Shut Down Completely	EV10a
6	Turned off non-critical equipment	EV10a
7	Shut Down Partially	EV10a
8	Rescheduled EMS	EV10a
9	Other	EV10a
77	<Record Verbatim>	EV10a
88	Refused	EV12

99	Don't Know	EV12

[If EV10 in (1 | |77)]

EV10a. How did you implement these demand reduction actions?

1	Fully Automated	EV11
2	Partially Automated	EV11
3	Manual	EV11
4	Does Not Apply	EV11
77	RECORD VERBATIM	EV11
88	Refused	EV11
99	Don't Know	EV11

EV11. What is your best estimate of the load reduction attained as a result of your curtailment actions? (Answer given as a % of total load)

1	0%	EV12a
2	1-5%	EV12a
3	6-10%	EV12a
4	11-20%	EV12a
5	21-30%	EV12a
6	31-50%	EV12a
7	51-75%	EV12a
8	76-100%	EV12a
77	<RECORD VERBATIM>	EV12a
88	Refused	EV12a
99	Don't Know	EV12a

EV12a. Prior to these events, did you increase your energy usage for a period of time to make up for the reduction that was about to occur?

1	Yes	PRIOR
2	No	EV12b
88	Refused	EV12b
99	Don't Know	EV12b

[IF EV12a = 1]

PRIOR. What actions did you take that increase your energy use PRIOR to the reduction period? (DO NOT READ)

1	Ran Extra Shifts earlier in the day	EV12b
2	Increased Production in off shifts	EV12b
3	Pre-Cooled the building	EV12b
77	<RECORD VERBATIM>	EV12b
88	Refused	EV12b
99	Don't Know	EV12b

EV12b. Once the event is over, did you increase your energy use for a period of time to make up for the reduction attained on the event day?

1	Yes	AFTER
2	No	EV13

88	Refused	EV13
99	Don't Know	EV13

[IF EV12b = 1]
AFTER. What actions did you take that increase your energy use AFTER the reduction period? (DO NOT READ)

1	Ran Extra Shifts	EV13
2	Increased Production in off shifts	EV13
77	<RECORD VERBATIM>	EV13
88	Refused	EV13
99	Don't Know	EV13

EV13. Did you experience any impacts on your organization in terms of personnel comfort or productivity?

1	Yes	IMPACT
2	No	EV14M
88	Refused	EV14M
99	Don't Know	EV14M

[IF EV13 = 1]

IMPACT. Please explain the impacts your organization experienced. (Do Not Read)

1	Staff complaints (lost hours, etc.)	EV14
2	Warm/Uncomfortable work environment	EV14
3	Lost Production	EV14
4	Financial Impact	EV14
5	Safety Concerns with limited lighting	EV14
77	<RECORD VERBATIM>	EV14
88	Refused	EV14
99	Don't Know	EV14

[IF RECALL = 0 then ask EV14, else skip to EV19]
READ: Next I have a few questions for you regarding the way in which you were notified about the event.

EV14. In your opinion, how effective was the process by which you were notified of the event? Would you say it was ….

1	Very effective	EV15
2	Somewhat effective	EV15
3	Somewhat ineffective (open end next)	EV14a
4	Very ineffective (open end next)	EV14a
5	Wasn't Notified	EV14
88	Refused	EV15
99	Don't Know	EV15

[IF EV14 in (3,4)]

EV14A: Why do you say that? (Do Not Read)

1	Notice was too late, not enough time to bid	EV15

2	Noticed was emailed and didn't check email	EV15
3	Can not bid if out of office	EV15
4	No follow up after initial call	EV15
77	<RECORD VERBATIM>	EV15
88	Refused	EV15
99	Don't Know	EV15

IF UTILITY = 'SCE' then ask EV15

EV15. [UTILITY's] primary mode of notification for an upcoming event is to give you a call on the telephone number that you provided to them. Was this your understanding of how you were to be notified?
[Could select 1 or 2 and 77]

1	Yes	EV16
2	No	EV16
77	Record Verbatim	EV16
88	Refused	EV16
99	Don't Know	EV16

IF UTILITY not equal to 'SCE' then ask EV15a

EV15A. [UTILITY's] primary mode of notification for an upcoming event is to send an email or an alpha numeric page. Was this your understanding of how you were to be notified?
[Could select 1 or 2 and 77]

1	Yes	EV16
2	No	EV16
77	Record Verbatim	EV16
88	Refused	EV16
99	Don't Know	EV16

EV16. Did you know that you can also receive a courtesy notification which is another form of notification? (FOR SCE "..such as a page, a fax, an email, etc.)

1	Yes	EV17
2	No	EV18
88	Refused	EV18
99	Don't Know	EV18

EV17. Are you currently signed up for any courtesy notifications?

1	Yes	CURTS
2	No	EV18
88	Refused	EV18
99	Don't Know	EV18

CURTS. Which courtesy notifications are you currently signed up for?

1	Beeper/Pager/Text Message	EV18
2	VoiceMail Phone	EV18
3	Cell Phone	EV18
4	Email	EV18
5	FAX	EV18
77	Other	EV18

88	Refused	EV18
99	Don't Know	EV18

EV18. Do you have any additional comments or concerns regarding the notification process?

1	No	EV18ANU
77	<RECORD VERBATIM>	EV18ANU
88	Refused	EV18ANU
99	Don't Know	EV18ANU

[IF (DBP = 1 or SC2(2|4)]

EV18ANU. As you may recall, the current DBP notification process allows you up to an hour to place a bid after being notified of a DBP event. Does this timeframe - a maximum of an hour - make it less likely that you will place a bid?

1	Yes	EV18CM
2	No	EV18AHM
88	Refused	EV18AHM
99	Don't Know	EV18AHM

[IF EV18ANU = 1 then ask EV18CM]

EV18CM. Why do you say that?

77	<RECORD VERBATIM>	EV18AHM
88	Refused	EV18AHM
99	Don't Know	EV18AHM

EV18AHM. How much time do you require to submit a bit after you have been notified? (round down – so if two hours put in #2)

1	One hour or Less	Q18DAY
2	Between 1 and 2 hours	Q18DAY
3	Between 2 and 4 hours	Q18DAY
4	Between 4 and 8 hours	Q18DAY
5	Between 8 and 24 hours	Q18DAY
6	More than 24 hours	Q18DAY
7	Current is Fine	Q18DAY
77	Other	Q18DAY
88	Refused	Q18DAY
99	Don't Know	Q18DAY

Q18DAY. How is you bidding time requirement different for DAY OF Events versus DAY AHEAD events? (Do Not Read – Accept multiple)
[Post "Currently PGE does not allow for DAY OF EVENT BIDDING so this question is hypothetical"]

1	They are not different	EV18B
2	Day-Of Events are Very Hard / Impossible	EV18B
3	Less time required for Day-Of Events	EV18B
4	Need earlier notification for Day-Of Events	EV18B
5	More time is required for Day-Of Events	EV18B
77	<RECORD VERBATIM>	EV18B

88	Refused	EV18B
99	Don't Know	EV18B

EV18B. How much time do you need to curtail load in response to the announcement of an event? (i.e. For DBP: the time between bid acceptance and event start hour, For CPP: the time between event notification and event start hour)

1	One hour or Less	EV19
2	Between 1 and 2 hours	EV19
3	Between 2 and 4 hours	EV19
4	Between 4 and 8 hours	EV19
5	Between 8 and 24 hours	EV19
6	More than 24 hours	EV19
7	Current is Fine	EV19
77	Other	EV19
88	Refused	EV19
99	Don't Know	EV19

[IF ^EV10(1)]

EV19. As you may know, some firms have on-site electricity generators for either back-up power supply or for supplemental needs. Does this location have any on-site electricity generators?

1	Yes	EV19A
2	No	ES1
88	Refused	ES1
99	Don't Know	ES1

[IF EV10 = 1 then Read: 'You mentioned earlier that you have back-up generators…"]

[IF EV10 = 1 or EV19=1]

EV19A. Under what conditions do you use your electricity generators?

1	In emergency situations for backup/standby purposes only	EV20
2	As an everyday supplement/replacement for electricity purchases from the grid	EV20
3	We have them but do not use them	EV20
77	<RECORD VERBATIM>	EV20
88	Refused	ES1
99	Don't know	ES1

EV20. Are their legal restrictions on the number of hours your on-site system can run during the summer?

1	Yes	ES1
2	No	ES1
77	<RECORD VERBATIM>	ES1
88	Refused	ES1
99	Don't Know	ES1

END OF SUMMER MODULE

[If ((CPP=1 and DBP=0 and SC2(1)) or SC2(3)) then Read:
"Next I would like to ask you to think about your overall experience with the CPP program for this past summer."]

[If ((CPP=0 and DBP=1 and SC2(1)) or SC2(2)) then Read:
"Next I would like to ask you to think about your overall experience with the DBP program for this past summer."]

[If ((CPP=1 and DBP=1 and SC2(1) or SC2(4)) then Read:
"Next I would like to ask you to think about your overall experience with the CPP and DBP programs for this past summer."]

[If (CPP=1 and SC2(1) or SC2(3|4))]

ES1. Thinking back over the summer (May-Present), how many events would you say were called for the CPP program? (Get a guess unless they have no idea)

0-12	Key in Number	ES2A
13	More than 12	ES2A
14	Refused	ES2A
15	Don't know	ES2A

ES2A. Were there more CPP Events than you expected, about as many as you expected, or fewer than you expected?

1	More than I expected	ES2B
2	About what I expected	ES2B
3	Fewer than I expected	ES2B
88	Refused	ES2B
99	Don't know	ES2B

[If ES1 in 1-13]

ES2B. For how many of the {Number from ES1} CPP events were you able to reduce your energy usage?

0-12	Key in Number	ES3
13	More than 12	ES3
14	Refused	ES3
15	Don't know	ES3

[If (DBP=1 and SC2(1) or SC2(2|4))]

ES3. Thinking back over the summer (May-Present), how many events would you say were called for the DBP program? (Can you give me your best guess)

0-12	Key in Number	ES4
13	More than 12	ES4
14	Refused	ES4
15	Don't know	ES4

ES4. Were there more DBP Events than you expected, about as many as you expected, or fewer than you expected?

1	More than I expected	ES5
2	About what I expected	ES5
3	Fewer than I expected	ES5
88	Refused	ES5
99	Don't know	ES5

[If ES3 in 1-13]

ES5. For how many of those {Number from ES3} DBP events did you submit a bid?

0-12	Key in Number	ES6
13	More than 12	ES6
14	Refused	ES6
15	Don't know	ES6

[If ES3 in 1-13]

ES6. For how many of those {Number from ES3} DBP events did you reduce your energy usage?

0-12	Key in Number	ES7
13	More than 12	ES7
14	Refused	ES8
15	Don't know	ES8

[If ES1 in (1-13) and ES2B < ES1 or If ES3 in (1-13) and ES6 < ES3 then ask ES7]

ES7. What were the main reasons you did you not reduce your energy usage for some of these events? (Do Not Read)

1	Operation was already was shut down	ES8
2	Didn't need to take action to save money	ES8
3	Could not respond in time	ES8
4	Not available to bid that hour	ES8
5	Never planning to bid for any event	ES8
6	Could not reduce load on that particular day	ES8
7	System Issue /No password	ES8
8	Do not remember why	ES8
9	Was not a mandatory reduction	ES8
77	<RECORD VERBATIM>	ES8
88	Refused	ES8
99	Don't know	ES8

ES8. How well prepared was your organization to manage the demand reductions called for by {Utility}'s Demand Response programs this summer? Would you say it was:

1	Very well prepared	ES9
2	Somewhat prepared	ES8A
3	Not at all prepared	ES8A
88	Refused	ES9
99	Don't know	ES9

[IF ES8 in (2,3) then ask ES8A]

ES8A. And why was that?

77	<RECORD VERBATIM>	ES9
88	Refused	ES9
99	Don't Know	ES9

ES9. How would you characterize the level of assistance you received in the development of load reduction options/strategies for this facility? Would you say …

1	As much support as our organization needed	ES11
2	Some support, but not as much as our organization needed	ES10
3	No support	ES10
88	Refused	ES10
99	Don't know	ES10

ES10. What additional support would you have found helpful in enabling you to reduce your demand?

77	<RECORD VERBATIM>	ES11
88	Refused	ES11
99	Don't know	ES11

ES11. Are you familiar with the Technical Assistance Incentive available to CPP and DBP program participants? {IF NEEDED: *The Technical Assistance Incentive pays for the cost of a professional audit to determine your facility's load reduction potential, up to $50/kW of load reduction, if you agree to participate in one of the eligible demand response initiatives*.}

1	Very Familiar	ES11A
2	Somewhat Familiar	ES11A
3	Not at all Familiar	ES12
88	Refused	ES12
99	Don't know	ES12

[If ES11 in (1,2) then ask ES11A]

ES11A. Did you utilize the technical assistance incentive?

1	Yes	ES12A
2	No	ES11B
88	Refused	ES12A
99	Don't know	ES12A

[If ES11A = 2 then ask ES11B]

ES11B. Why not?

77	<RECORD VERBATIM>	ES12A
88	Refused	ES12A
99	Don't know	ES12A

ES12A-ES12D. Now I'd like to describe some reasons why organizations might decide to participate in demand response programs. On a 1 to 5 scale, where 1 indicates insignificant and 5 indicates extremely significant, please indicate how significant each of the following reasons is

to your decision to participate in the demand response program for this location. [ROTATE RANDOMLY]
How significant a reasons is ….

ES12A.	Being a good corporate citizen	ES13
ES12B.	Avoiding rolling blackouts	ES13
ES12C.	The amount of potential bill savings	ES13
ES12D.	Being able to participate in the program without significantly affecting your business operations.	ES13

ES13A-ES13D. I'd also like to now describe some reasons organizations might not participate in demand response programs or would achieve only small demand reductions. On a 1 to 5 scale, where 1 indicates insignificant and 5 indicates extremely significant, please indicate how significant each of the following is as a concern about demand response program participation at this location. [ROTATE RANDOMLY]
How significant a concern is ….

ES13A.	The effect on occupant comfort	ES14
ES13B.	The effect on products or productivity	ES14
ES13C.	The amount of potential bill savings	ES14
ES13D.	The inability to reduce peak loads	ES14

ES14A-ES14G. Now, based on your participation this summer, I would like you to rate your satisfaction with various aspects of the [PROGRAM] program. Please tell me if you were very satisfied, somewhat satisfied, somewhat dissatisfied, or very dissatisfied with each of the following:

ES14a.	The process by which you were notified about the DR event	
ES14b.	The amount of advanced notification	
ES14c1.	[If CPP = 1 and SC2=1 or SC2 in (3,4)] The number of CPP events called	
ES14c2.	[If DBP = 1 and SC2=1 or SC2 in (2,4)] The number of DBP events called	
ES14d1.	[If CPP = 1 and SC2=1 or SC2 in (3,4)] The duration of the CPP events called	
ES14d2.	[If DBP = 1 and SC2=1 or SC2 in (2,4)] The duration of the DBP events called	
ES14e.	The program-related customer service you received from your utility	
ES14f.	[If CPP = 1 and SC2=1 or SC2 in (3,4)] The CPP rates you paid	
ES14g1.	[If CPP = 1 and SC2=1 or SC2 in (3,4)] The amount of the bill credit offered for participating in the CPP program	
ES14g2.	[If DBP = 1 and SC2=1 or SC2 in (2,4)] The amount of incentives offered for participating in the DBP program	

[[If CPP = 1 and SC2=1 or SC2 in (3,4)]]

ES15_CPP. Overall, how satisfied are you with your participation in the CPP program this past summer? (Next question is an open-end to capture why)

1	Very satisfied	ES16_CPP
2	Somewhat satisfied	ES16_CPP
3	Somewhat dissatisfied	ES16_CPP
4	Very dissatisfied	ES16_CPP
88	Refused	ES17_CPP

99	Don’t Know	ES17_CPP

[If ES15_CPP in 1 to 5 then ask ES16_CPP]

ES16_CPP. Why is that?

77	<RECORD VERBATIM>	ES17_CPP
88	Refused	ES17_CPP
99	Don’t know	ES17_CPP

ES17_CPP. Do you have any suggestions for improving the CPP program?

77	<RECORD VERBATIM>	ES18_CPP
88	Refused	ES18_CPP
99	Don’t know	ES18_CPP

ES18_CPP. Do you plan to participate in the CPP program next summer?
(Next question is an open-end for the why)

1	Yes	ES19_CPP
2	No	ES19_CPP
88	Refused	ES25
99	Don’t know	ES25

[If ES18_CPP in 1 or2 then ask ES19_CPP]

ES19_CPP. Why or why not?

77	<RECORD VERBATIM>	ES25
88	Refused	ES25
99	Don’t know	ES25

[If DBP = 1 and SC2=1 or SC2 in (2,4)]

ES20_DBP. Overall, how satisfied are you with your participation in the DBP program this past summer? (Next question is an open-end for the why)

1	Very satisfied	ES21_DBP
2	Somewhat satisfied	ES21_DBP
3	Somewhat dissatisfied	ES21_DBP
4	Very dissatisfied	ES21_DBP
88	Refused	ES22_DBP
99	Don’t Know	ES22_DBP

[If ES20_DBP in 1 to 5 then ask ES21_DBP]

ES21_DBP. Why is that?

77	<RECORD VERBATIM>	ES22_DBP
88	Refused	ES22_DBP
99	Don’t know	ES22_DBP

ES22_DBP. Do you have any suggestions for improving the DBP program?

77	<RECORD VERBATIM>	ES23_DBP
88	Refused	ES23_DBP

99	Don't know	ES23_DBP

ES23_DBP. Do you plan to participate in the DBP program next summer?
(Next question is an open-end for the why)

1	Yes	ES24_DBP
2	No	ES24_DBP
88	Refused	ES25
99	Don't know	ES25

[If ES23_DBP in 1 or2 then ask ES24_DBP]

ES24_DBP. Why do you say that?

77	<RECORD VERBATIM>	ES25
88	Refused	ES25
99	Don't know	ES25

ES25. Do you plan to participate in another demand response program or tariff?

1	Yes	ES25A
2	No	ES26
88	Refused	ES26
99	Don't know	ES26

ES25A. Which one(s)? SELECT ALL THAT APPLY

1	CPA-DRP	ES25B
2	BIP	ES25B
3	OBMC/POBMC	ES25B
4	I-6 / AL-TOU-CP / Non-Firm	ES25B
5	SLRP	ES25B
6	RBRP	ES25B
7	HPO	ES25B
8	CPP	ES25B
9	DBP	ES25B
77	Other <record verbatim>	ES25B
88	Refused	ES25B
99	Don't know	ES25B

[IF ES18_CPP = 2 or ES23_DBP = 2 and ES25 = 1 then ask ES25B]

ES25B. Why do you plan to switch to the other Demand Response program?

77	<RECORD VERBATIM>	ES26A
88	Refused	ES26A
99	Don't know	ES26A

[IF ES18_CPP= 1 and CPP = 1 then ask ES26A]

ES26A. For next summer, do you think your demand reduction for CPP program events will increase, decrease, or stay about the same?

1	Increase	ES30
2	Decrease	ES30

3	Stay about the same	ES30
88	Refused	ES30
99	Don't know	ES30

[IF ES23_DBP = 1 and DBP = 1 then ask ES26B]

ES26B. For next summer, do you think your demand reduction for DBP program events will increase, decrease, or stay about the same?

1	Increase	ES30
2	Decrease	ES30
3	Stay about the same	ES30
88	Refused	ES30
99	Don't know	ES30

ES30. As a result of your experience with the [PROGRAM] program(s) this past summer, would you say you are: much more knowledgeable, somewhat more knowledgeable, or no more knowledgeable about managing your energy usage at times of peak demand?

1	Much more knowledgeable	EM3
2	Somewhat more knowledgeable	EM3
3	No more knowledgeable	EM3
88	Refused	EM3
99	Don't know	EM3

READ : We are almost done I just have a couple more questions regarding your organizations attitudes towards electricity markets and prices.

EM3. How closely does your organization monitor and analyze electricity markets and prices? Would you say,

1	Very Closely	EM5
2	Somewhat Closely	EM5
3	Not Very Closely	EM5
88	Refused	EM5
99	Don't know	EM5

EM5. In your organization's view, how likely is it that California's power supplies will be inadequate to meet expected power demand over the next three years? Would you say:

1	Very Likely	EM7
2	Somewhat Likely	EM7
3	Somewhat Unlikely	EM7
4	Very Unlikely	EM7
88	Refused	EM7
99	Don't know	EM7

EM7. How concerned is your organization about energy costs relative to other costs of running your business?

1	Very Concerned	EC5
2	Somewhat Concerned	EC5
3	Relatively Unconcerned	EC5

88	Refused	EC5
99	Don't know	EC5

FIRMOGRAPHIC CHARACTERISTICS

Read: "Now I'd like to ask a few quick questions about this facility."

EC5. What percent of your organization's total annual operating costs do energy costs represent?

1	Less than 1 percent	EC9A
2	1 to 4 percent	EC9A
3	5 to 10 percent	EC9A
4	11 to 25 percent	EC9A
5	Over 25	EC9A
88	Refused	EC9A
99	Don't know	EC9A

EC9A . Which of the following is the LARGEST end use in terms of electricity consumption for this facility?

1	Lighting	EC9B
2	HVAC	EC9B
3	Continuous processing	EC9B
4	Batch processing	EC9B
5	Refrigeration	EC9B
77	Other, Specify______________	EC9B
88	Refused	EC9B
99	Don't know	EC9B

[If EC9A is in 1-77 then ask EC9B]

EC9B. And which would you say used the SECOND most electricity?

1	Lighting	CL1
2	HVAC	CL1
3	Continuous processing	CL1
4	Batch processing	CL1
5	Refrigeration	CL1
77	Other, Specify______________	CL1
88	Refused	CL1
99	Don't know	CL1

CLOSE

READ: And finally, …

CL1. Do you have any final comments or input regarding your experiences with the demand response programs or events?

1	No Comments	
77	<RECORD VERBATIM>	
88	Refused	
99	Don't Know	

Those are all the questions I have for you today. Thank you very much for your time.

APPENDIX E
POST-EVENT /FINAL EVALUATION SURVEY TABLES

Exhibit E.1
CPP Demand Reduction Actions

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
CPP_A. Did you take demand reduction actions in response to the CPP event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	75%	80%	70%	81%	69%	93%	84%	54%	85%	100%	54%
No	21%	20%	26%	10%	31%	7%	16%	34%	15%	0%	35%
Don't know	4%	0%	4%	10%	0%	0%	0%	12%	0%	0%	11%
N	150	30	70	31	13	29	58	50	75	18	57

* N is the number of events.

Exhibit E.2
CPP Multiple Facilities

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
CPP_B. For customers with multiple facilities, at which facilities did you take demand reduction actions?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
All facilities	68%	40%	73%	71%	0%	14%	54%	95%	66%	75%	68%
N	41	5	22	14	0	7	13	20	29	12	41

* N is the number of events.

Exhibit E.3
CPP Reasons for No Action

DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY	
CPP_C. Why didn't your firm take any demand reduction action?	Total
Operation was already shut down	19%
Don't need to take action to save money	10%
Could not respond that fast	10%
Could not shut down	32%
No one was available to reduce load	13%
Did not get the message	3%
Other priorities	3%
Other	10%
N	31

* N is the number of events.

Exhibit E.4
CPP Likelihood of Taking Action

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
CPP4A. How likely are you to take demand reduction actions for future CPP events?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very likely	67%	89%	65%	56%	50%	90%	72%	43%	80%	75%	47%
Somewhat likely	17%	11%	17%	22%	25%	10%	22%	21%	12%	25%	24%
Neither likely nor unlikely	4%	0%	4%	11%	0%	0%	0%	14%	4%	0%	6%
Somewhat unlikely	7%	0%	9%	11%	0%	0%	6%	14%	4%	0%	12%
Not at all likely	4%	0%	4%	0%	25%	0%	0%	7%	0%	0%	12%
N	46	9	23	9	4	10	18	14	25	4	17

* N is the number of respondents.

Exhibit E.5
CPP Suggestions

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
CPP4B. Is there anything that your utility can do to help you take demand reduction actions for future CPP events?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Nothing	62%	50%	62%	56%	80%	67%	55%	61%	53%	67%	76%
Advertising-make public aware of program	21%	30%	19%	22%	20%	11%	25%	22%	25%	33%	12%
More warning before an event	6%	10%	4%	11%	0%	0%	10%	6%	6%	0%	6%
More options for notification	8%	0%	11%	14%	0%	14%	0%	15%	10%	0%	7%
Give feedback after event	3%	0%	6%	0%	0%	0%	8%	0%	5%	0%	0%
Monitor use and give updates during event	3%	20%	0%	0%	0%	14%	0%	0%	5%	0%	0%
Other	2%	0%	4%	0%	0%	0%	5%	0%	3%	0%	0%
N	52	10	26	9	5	9	20	18	32	3	17

* N is the number of events.

Exhibit E.6
DBP Placed a Bid

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
DBP_A. Did you place a bid for the DBP event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	24%	19%	24%	30%	21%	21%	24%	37%	0%	20%	44%	71%	24%
No	72%	77%	74%	66%	74%	74%	75%	59%	0%	77%	53%	14%	72%
Don't know	3%	3%	2%	4%	6%	5%	1%	4%	0%	4%	3%	14%	3%
N	176	31	58	53	34	76	68	27	0	142	34	7	176

* N is the number of events.

Exhibit E.7
DBP Multiple Facility Bid

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
DBP_B. At which facilities did you take demand reduction actions?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
All facilities	17%	0%	50%	0%	0%	50%	0%	0%	0%	0%	50%
N	6	2	2	1	1	2	2	2	0	4	2

* N is the number of events.

Exhibit E.8
DBP Reasons for No Bid

DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY	
DBP_C. Why didn't your firm place a bid for the DBP event?	Total
Operation was already shut down	3%
Don't need to take action to save money	2%
Could not respond that fast	4%
Not available to bid that hour	4%
Never planning to bid for any event	10%
Could not reduce load on that particular day	39%
System issue/no password	9%
The event was cancelled	4%
People responsible for bidding were not there	10%
Did not get notification in time	9%
Unhappy with first bid	2%
Other	3%
Don't know	4%
N	128

* N is the number of events.

Exhibit E.9
DBP Demand Reduction Actions

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
DBP_D. Did you take any demand reduction actions at any of your facilities for the DBP event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	40%	31%	42%	48%	34%	40%	34%	59%	33%	35%	68%	82%	40%
No	53%	61%	53%	48%	54%	53%	61%	34%	52%	59%	29%	9%	53%
Don't know	6%	8%	5%	3%	12%	8%	6%	7%	15%	6%	3%	9%	6%
N	203	36	64	62	41	80	89	29	27	142	34	11	203

* N is the number of events.

Exhibit E.10
DBP Bid and Action

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
DBP_D. For those who did place a bid for the DBP event: Did you take any demand reduction actions at any of your facilities for the DBP event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	95%	83%	100%	100%	86%	100%	88%	100%	0%	96%	93%
No	5%	17%	0%	0%	14%	0%	12%	0%	0%	4%	7%
Don't know	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
N	43	6	14	16	7	16	16	10	0	28	15

* N is the number of events.

Exhibit E.11
DBP No Bid and Action

DBP_D. For those who did not place a bid for the DBP event: Did you take any demand reduction actions at any of your facilities for the DBP event?	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	23%	17%	19%	31%	28%	23%	17%	38%	0%	19%	50%
No	73%	75%	74%	69%	72%	70%	81%	62%	0%	76%	50%
Don't know	4%	8%	7%	0%	0%	7%	2%	0%	0%	5%	0%
N	127	24	43	36	25	56	52	16	0	109	18

* N is the number of events.

Exhibit E.12
DBP Multiple Facility Actions

DBP_D2. At which facilities did you take demand reduction actions?	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
All facilities	19%	0%	20%	20%	33%	0%	33%	0%	25%	17%	0%
N	16	3	5	5	3	6	9	1	4	12	0

* N is the number of events.

Exhibit E.13
DBP Reasons for No Action

DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY	
DBP1_E. Why didn't your firm take any demand reduction actions for this event?	Total
Operation was already shut down	4%
Could not respond that fast	4%
Not available to bid that hour	6%
Never planning to bid for any event	4%
Could not reduce load on that particular day	42%
System issue/no password	5%
Do not remember why	1%
Was not a mandatory reduction	8%
Did not get notification in time	5%
Person in charge of shutdown was not there	8%
We are on an interruptible rate schedule	5%
No reason	2%
Other	7%
Don't know	4%
N	106

* N is the number of events.

Exhibit E.14
DBP Bid and Action Comparison

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
DBP_F. How did your actual reduction compare to the demand reduction you bid?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Reduction was close to what was bid	41%	100%	21%	50%	29%	19%	57%	60%	0%	37%	50%
Reduction was much less than what was bid	17%	0%	29%	13%	14%	25%	21%	0%	0%	15%	21%
Reduction was much more than what was bid	15%	0%	14%	13%	29%	13%	14%	10%	0%	22%	0%
Other	15%	0%	7%	19%	29%	19%	7%	20%	0%	7%	29%
Don't know	12%	0%	29%	6%	0%	25%	0%	10%	0%	19%	0%
N	41	4	14	16	7	16	14	10	0	27	14

* N is the number of events.

Exhibit E.15
DBP Reasons for Reduction Difference

DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY	
DBP1_G. Why was your actual reduction different from what was bid?	Total
Because I was able to	40%
We use such little energy it's hard to reduce more	20%
Did not have time to track curtailment	20%
10 day baseline is disadvantage for us	20%
Incentives were too low, not worth lost productivity	20%
Other	60%
Don't know	20%
N	5

* N is the number of events.

Exhibit E.16
DBP Likelihood of Bidding

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
DBP5A. What is the likelihood that you will place bids for future DBP events?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very likely	38%	38%	38%	47%	25%	37%	35%	44%	40%	38%	33%
Somewhat likely	34%	31%	38%	31%	36%	30%	40%	31%	40%	33%	33%
Neither likely nor unlikely	4%	6%	5%	3%	4%	2%	5%	6%	8%	4%	0%
Somewhat unlikely	16%	19%	13%	14%	21%	21%	12%	13%	4%	18%	25%
Not at all likely	8%	6%	5%	6%	14%	9%	7%	6%	8%	7%	8%
N	119	16	39	36	28	43	57	16	25	82	12

* N is the number of respondents.

Exhibit E.17
DBP Suggestions

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
DBP5B. Is there anything that your utility can do to help you bid on future DBP events?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Nothing	52%	60%	55%	46%	48%	43%	61%	42%	56%	51%	50%
Give more notice before an event	26%	28%	19%	33%	24%	31%	25%	16%	32%	27%	0%
Provide tutorial on how to use system	1%	0%	2%	0%	0%	0%	0%	5%	0%	1%	0%
Give us more info about the program	2%	0%	3%	3%	0%	3%	0%	6%	0%	3%	0%
Increase incentives	2%	0%	0%	3%	5%	0%	2%	6%	0%	1%	8%
Notify more than one person	2%	0%	3%	3%	0%	3%	0%	6%	0%	3%	0%
Reduce load requirement	1%	0%	3%	0%	0%	3%	0%	0%	0%	1%	0%
Other	16%	12%	17%	13%	24%	20%	13%	21%	12%	14%	42%
N	136	25	42	39	29	49	64	19	34	90	12

* N is the number of respondents.

Exhibit E.18
Demand Reduction Actions

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV10. What demand reduction actions did you take in response to the most recent event in which you participated?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Use back generators	12%	0%	13%	15%	17%	12%	8%	11%	10%	15%	6%	3%	18%
Allowed temperature to rise in the occipied spaces	28%	43%	31%	22%	17%	46%	16%	28%	28%	18%	53%	38%	27%
Reduced overhead lighting	29%	64%	22%	22%	25%	46%	30%	6%	28%	33%	24%	30%	30%
Reduced or shut off some or all production processes	28%	21%	25%	30%	33%	23%	32%	28%	14%	35%	35%	19%	30%
Shut down completely	10%	0%	16%	11%	8%	8%	14%	11%	10%	13%	6%	14%	7%
Turned off non-critical equipment	21%	36%	22%	19%	8%	19%	16%	33%	34%	8%	29%	32%	14%
Shut down partially	13%	0%	13%	22%	8%	12%	19%	6%	10%	18%	6%	14%	14%
Rescheduled EMS	3%	7%	3%	4%	0%	8%	0%	6%	3%	5%	0%	3%	4%
Other	6%	0%	7%	0%	23%	0%	10%	6%	6%	6%	6%	7%	12%
N	86	14	32	27	12	26	37	18	29	40	17	37	56

* N is the number of respondents.

Exhibit E.19
Implementing Reductions

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV10A. How did you implement these demand reduction actions?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Fully automated	6%	0%	13%	4%	0%	9%	3%	11%	7%	9%	0%	6%	6%
Partially automated	16%	0%	23%	12%	30%	27%	9%	22%	14%	14%	27%	18%	24%
Manual	77%	100%	63%	84%	70%	64%	88%	67%	79%	77%	73%	76%	71%
Other	1%	0%	0%	4%	0%	5%	0%	0%	0%	3%	0%	0%	2%
N	79	13	30	25	10	22	34	18	29	35	15	34	51

* N is the number of respondents.

Exhibit E.20
Load Reduction from Curtailment

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV11. What is your best estimate of the load reduction attained as a result of your curtailment actions?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
0 percent	3%	7%	0%	4%	8%	4%	5%	0%	3%	5%	0%	3%	4%
1 to 5 percent	10%	21%	6%	4%	25%	8%	8%	17%	13%	5%	18%	11%	9%
6 to 10 percent	15%	21%	15%	15%	8%	23%	16%	6%	3%	23%	18%	8%	20%
11 to 20 percent	16%	14%	15%	19%	17%	12%	16%	22%	17%	18%	12%	11%	21%
21 to 30 percent	8%	7%	12%	4%	8%	8%	8%	11%	7%	10%	6%	11%	5%
31 to 50 percent	8%	0%	12%	7%	0%	0%	11%	11%	13%	5%	6%	13%	4%
51 to 75 percent	7%	7%	6%	7%	8%	15%	3%	0%	3%	5%	18%	11%	7%
76 to 100 percent	14%	7%	12%	19%	17%	8%	18%	11%	10%	15%	18%	16%	13%
Don't know	18%	14%	21%	22%	8%	23%	16%	22%	30%	15%	6%	18%	18%
N	87	14	33	27	12	26	38	18	30	40	17	38	56

* N is the number of respondents.

Exhibit E.21
Increased Use Prior to Event

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV12A. Prior to these events, did you increase your energy usage for a period of time to make up for the reduction that was about to occur?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	5%	7%	6%	4%	0%	4%	5%	6%	3%	5%	6%	5%	4%
No	94%	93%	94%	93%	100%	96%	95%	89%	93%	95%	94%	92%	96%
Don't know	1%	0%	0%	4%	0%	0%	0%	6%	3%	0%	0%	3%	0%
N	87	14	33	27	12	26	38	18	30	40	17	38	56

* N is the number of respondents.

Exhibit E.22
Increased Use After Reduction

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV12B. Once the event was over, did you increase your energy use after the reduction period?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	17%	21%	18%	15%	17%	15%	18%	22%	17%	18%	18%	26%	11%
No	83%	79%	82%	85%	83%	85%	82%	78%	83%	83%	82%	74%	89%
N	87	14	33	27	12	26	38	18	30	40	17	38	56

* N is the number of respondents.

Exhibit E.23
Organization Impacted

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV13. Did you experience any impacts on your organization in terms of personnel comfort or productivity?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	26%	36%	21%	22%	33%	23%	39%	6%	27%	28%	24%	29%	25%
No	74%	64%	79%	78%	67%	77%	61%	94%	73%	73%	76%	71%	75%
N	87	14	33	27	12	26	38	18	30	40	17	38	56

* N is the number of respondents.

Exhibit E.24
Impacts on Organization

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
IMPACT. Please explain the impacts your organization experienced.	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Staff complaints (lost hours, etc.)	28%	20%	45%	14%	20%	38%	17%	100%	36%	14%	50%	43%	18%
Warm/uncomfortable work environment	24%	20%	36%	29%	0%	25%	22%	50%	27%	29%	0%	21%	24%
Lost production	38%	20%	27%	71%	20%	13%	50%	0%	27%	50%	25%	29%	47%
Financial impact	10%	0%	9%	0%	40%	13%	11%	0%	9%	7%	25%	14%	6%
Safety concerns with limited lighting	7%	20%	0%	0%	20%	0%	11%	0%	9%	7%	0%	0%	12%
Other	3%	20%	0%	0%	0%	13%	0%	0%	0%	7%	0%	0%	6%
N	29	5	11	7	5	8	18	2	11	14	4	14	17

* N is the number of respondents.

Exhibit E.25
Effectiveness of Notification Process

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV14. In your opinion, how effective was the process by which you were notified of the event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very effective	60%	60%	60%	64%	53%	53%	60%	70%	65%	57%	63%	67%	59%
Somewhat effective	27%	28%	29%	27%	22%	33%	23%	27%	27%	27%	26%	26%	26%
Somewhat ineffective	6%	4%	5%	2%	13%	8%	7%	0%	4%	6%	7%	2%	7%
Very ineffective	4%	8%	2%	4%	3%	2%	5%	3%	0%	6%	4%	4%	3%
Wasn't notified	2%	0%	2%	2%	6%	2%	4%	0%	4%	2%	0%	0%	3%
Don't know	1%	0%	2%	0%	3%	2%	1%	0%	0%	2%	0%	0%	2%
N	161	25	58	45	32	49	75	30	48	86	27	46	122

* N is the number of respondents.

Exhibit E.26
Reasons for Notice Effectiveness

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV14A. Why do you give that effectiveness rating?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Notice was too late, not enough time to bid	47%	67%	25%	67%	40%	40%	44%	100%	50%	40%	67%	100%	38%
Notice was emailed and didn't check email	20%	0%	50%	0%	20%	0%	22%	100%	0%	20%	33%	50%	15%
Can not bid if out of office	13%	33%	25%	0%	0%	0%	22%	0%	50%	10%	0%	0%	15%
No follow up after initial call	13%	0%	25%	0%	20%	40%	0%	0%	0%	20%	0%	0%	15%
Other	13%	0%	0%	33%	20%	20%	11%	0%	0%	10%	33%	0%	15%
N	15	3	4	3	5	5	9	1	2	10	3	2	13

* N is the number of respondents.

Exhibit E.27
Notification Awareness

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV15. Your utility's primary mode of notification for an upcoming event is to give you a call on the telephone number that you provided to them. Was this your understanding of how you were to be notified?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	72%	80%	68%	81%	59%	69%	77%	62%	57%	81%	58%	60%	74%
No	21%	15%	24%	14%	31%	20%	20%	27%	41%	9%	37%	34%	19%
No - email	18%	17%	21%	11%	29%	20%	12%	27%	18%	13%	38%	43%	15%
No - text message	4%	0%	4%	4%	7%	4%	6%	0%	18%	0%	0%	7%	4%
Other	4%	10%	4%	0%	3%	4%	3%	4%	3%	5%	0%	6%	3%
Don't know	3%	0%	4%	2%	3%	7%	2%	0%	0%	5%	0%	0%	4%
N	142	20	50	42	29	45	65	26	37	86	19	35	113

* N is the number of respondents.

Exhibit E.28
Courtesy Notification Awareness

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV16. Did you know that you can also receive a courtesy notification which is another form of notification other than the main phone call such as a page, a fax, an email, etc.?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	80%	84%	83%	76%	78%	88%	79%	77%	75%	84%	78%	80%	81%
No	18%	16%	14%	22%	22%	10%	19%	23%	23%	14%	22%	17%	17%
Don't know	2%	0%	3%	2%	0%	2%	3%	0%	2%	2%	0%	2%	2%
N	161	25	58	45	32	49	75	30	48	86	27	46	122

* N is the number of respondents.

Exhibit E.29
Courtesy Notification

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV17. Are you currently signed up for any courtesy notifications?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	84%	86%	80%	91%	80%	84%	82%	88%	97%	76%	90%	95%	81%
No	10%	10%	10%	9%	12%	7%	12%	13%	0%	16%	5%	0%	13%
Don't know	6%	5%	10%	0%	8%	9%	7%	0%	3%	8%	5%	5%	6%
N	132	21	50	35	25	44	60	24	37	74	21	37	102

* N is the number of respondents.

Exhibit E.30
Modes of Notification

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
CURTS. Which courtesy notifications are you currently signed up for?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Beeper/pager/text message	23%	17%	21%	28%	25%	14%	29%	24%	51%	7%	16%	26%	21%
Voice mail	7%	11%	10%	3%	5%	11%	8%	0%	9%	4%	16%	14%	6%
Cell phone	16%	17%	15%	19%	15%	11%	19%	24%	23%	14%	11%	23%	13%
Email	85%	94%	85%	81%	85%	89%	79%	90%	83%	86%	89%	91%	83%
Fax	8%	6%	10%	6%	10%	11%	8%	5%	0%	13%	11%	6%	10%
Other	6%	11%	5%	6%	5%	5%	6%	10%	9%	5%	5%	11%	5%
Don't know	1%	0%	0%	3%	0%	3%	0%	0%	0%	2%	0%	0%	1%
N	110	18	39	32	20	37	48	21	35	56	19	35	82

* N is the number of respondents.

Exhibit E.31
Effect of One Hour Timeframe

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
EV18A. The current DBP notification process allows you up to an hour to place a bid after being notified of a DBP event. Does this timeframe - a maximum of an hour - make it less likely that you will place a bid?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	50%	40%	42%	63%	48%	49%	52%	38%	58%	48%	36%
No	49%	60%	52%	38%	52%	46%	48%	62%	42%	50%	55%
Don't know	2%	0%	6%	0%	0%	5%	0%	0%	0%	2%	9%
N	101	15	31	32	23	37	48	13	24	66	11

* N is the number of respondents.

Exhibit E.32
Reasons for Effect of Timeframe

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
EV18CM. Why does this timeframe - a maximum of an hour - make it less likely that you will place a bid?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Person in charge of bidding is busy, hard to reach	38%	20%	38%	37%	50%	43%	30%	50%	50%	36%	25%
Takes time to coordinate shutdown within company	15%	0%	25%	11%	25%	21%	10%	25%	0%	14%	50%
Once equipment has started running cannot stop it	3%	0%	13%	0%	0%	0%	5%	0%	0%	4%	0%
Cannot react that quickly	45%	80%	25%	53%	25%	36%	55%	25%	50%	46%	25%
Other	38%	38%	50%	21%	50%	44%	35%	33%	50%	36%	0%
N	40	5	8	19	8	14	20	4	8	28	4

* N is the number of respondents.

Exhibit E.33
Time to Submit a Bid

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY										
EV18AHM. How much time do you require to submit a bid after you have been notified?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
One hour or less	26%	33%	33%	19%	21%	32%	19%	33%	21%	25%	38%
Between 1 and 2 hours	13%	13%	6%	28%	4%	6%	17%	13%	13%	13%	15%
Between 2 and 4 hours	18%	20%	18%	19%	17%	24%	12%	27%	17%	19%	15%
Between 4 and 8 hours	8%	13%	6%	3%	13%	6%	12%	0%	4%	7%	15%
Between 8 and 24 hours	14%	0%	15%	16%	21%	12%	17%	13%	17%	16%	0%
More than 24 hours	4%	0%	3%	6%	4%	3%	4%	7%	4%	4%	0%
Current is fine	6%	13%	6%	0%	8%	6%	8%	0%	8%	6%	0%
Other	2%	0%	0%	3%	4%	3%	2%	0%	0%	1%	8%
Refused	1%	0%	0%	3%	0%	0%	0%	7%	0%	1%	0%
Don't know	8%	7%	12%	3%	8%	9%	10%	0%	17%	4%	8%
N	104	15	33	32	24	34	52	15	24	67	13

* N is the number of respondents.

Exhibit E.34
Day of Events

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
Q18DAY. How is your bidding time requirement different for day-of-events versus day-ahead-events?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
They are not different (similiar)	50%	53%	52%	41%	61%	49%	48%	62%	33%	56%	55%	33%	50%
Day-of-events are very hard/impossible	12%	20%	6%	13%	13%	8%	17%	8%	17%	9%	18%	0%	12%
Less time required for day-of events	1%	0%	0%	3%	0%	0%	2%	0%	4%	0%	0%	0%	1%
Need earlier notification for day-of-events	11%	7%	10%	19%	4%	14%	8%	8%	13%	9%	18%	33%	11%
More time is required for day-of-events	9%	7%	10%	13%	4%	5%	13%	8%	8%	11%	0%	17%	9%
Prefer day-ahead-events	9%	7%	16%	3%	9%	16%	6%	0%	13%	8%	9%	0%	9%
Other	2%	7%	3%	0%	0%	5%	0%	0%	0%	3%	0%	0%	2%
Refused	1%	0%	0%	0%	4%	0%	0%	8%	0%	2%	0%	0%	1%
Don't know	5%	0%	3%	9%	4%	3%	6%	8%	13%	3%	0%	17%	5%
N	101	15	31	32	23	37	48	13	24	66	11	6	101

* N is the number of respondents.

Exhibit E.35
Time to Curtail

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV18B. How much time do you need to curtail load in response to the announcement of an event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
One hour or less	45%	36%	43%	44%	55%	43%	43%	48%	38%	46%	53%	25%	49%
Between 1 and 2 hours	14%	18%	16%	10%	10%	20%	10%	14%	15%	12%	18%	18%	14%
Between 2 and 4 hours	12%	9%	18%	13%	3%	14%	13%	10%	8%	16%	6%	7%	14%
Between 4 and 8 hours	4%	0%	2%	3%	10%	0%	7%	0%	5%	4%	0%	0%	4%
Between 8 and 24 hours	9%	14%	4%	10%	10%	0%	13%	14%	15%	6%	6%	18%	6%
More than 24 hours	5%	18%	4%	3%	0%	7%	3%	5%	10%	2%	6%	14%	3%
Current is fine	5%	0%	8%	8%	0%	5%	7%	0%	5%	5%	6%	18%	3%
Other	6%	5%	4%	8%	10%	11%	3%	10%	3%	8%	6%	0%	8%
Don't know	1%	0%	0%	3%	0%	0%	1%	0%	0%	1%	0%	0%	1%
N	139	22	49	39	29	44	70	21	39	83	17	28	118

* N is the number of respondents.

Exhibit E.36
On-site Generators

	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
EV19. Does this site have any on-site electricity generators?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	48%	44%	45%	50%	56%	60%	35%	62%	41%	49%	58%	40%	52%
No	52%	56%	55%	50%	44%	40%	65%	38%	59%	51%	42%	60%	48%
N	156	25	56	42	32	48	74	29	46	84	26	45	117

* N is the number of respondents.

Exhibit E.37
Use of Generators

EV19A. Under what conditions do you use your electricity generators?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
For emergency backup/standby purposes only	95%	100%	93%	92%	100%	97%	93%	95%	95%	95%	94%	100%	94%
As everyday supplement for electricity purchases from grid	2%	0%	4%	4%	0%	0%	4%	5%	5%	0%	6%	0%	3%
Load reduction for demand bidding or I-6 program	12%	10%	16%	10%	8%	12%	13%	6%	0%	19%	7%	0%	14%
Other	1%	0%	0%	0%	6%	0%	4%	0%	5%	0%	0%	0%	1%
N	82	11	28	25	18	31	28	19	22	44	16	19	68

* N is the number of respondents.

Exhibit E.38
Generator Restrictions

EV20. Are there legal restrictions on the number of hours your on-site system can run during the summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
	DEMAND RESPONSE PARTICIPANT POST EVENT SURVEY												
Yes	56%	27%	57%	58%	67%	52%	59%	68%	62%	48%	69%	74%	52%
No	41%	73%	39%	38%	28%	45%	37%	32%	33%	50%	25%	26%	43%
Don't know	4%	0%	4%	4%	6%	3%	4%	0%	5%	2%	6%	0%	4%
N	81	11	28	24	18	31	27	19	21	44	16	19	67

* N is the number of respondents.

Exhibit E.39
CPP Number of Events

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES1. Thinking back over the summer, how many events would you say were called for the CPP program?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
3	22%	29%	11%	29%	50%	14%	8%	31%	19%	0%	29%
4	16%	0%	33%	0%	0%	0%	23%	23%	24%	0%	7%
5	11%	14%	6%	14%	25%	14%	15%	8%	14%	0%	7%
6	16%	43%	6%	14%	0%	14%	8%	15%	24%	0%	7%
7	14%	0%	11%	29%	25%	29%	15%	8%	10%	0%	21%
8-12	11%	14%	11%	14%	0%	14%	15%	8%	0%	100%	14%
Don't know	11%	0%	22%	0%	0%	14%	15%	8%	10%	0%	14%
N	37	7	18	7	4	7	13	13	21	2	14

* N is the number of respondents.

Exhibit E.40
CPP Events Expected

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES2A. Were there more, less, or about as many CPP events as you expected?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
More than I expected	14%	14%	11%	14%	25%	0%	15%	23%	10%	50%	14%
About what I expected	41%	57%	39%	43%	0%	43%	31%	38%	38%	50%	43%
Fewer than I expected	38%	14%	44%	43%	50%	43%	46%	38%	43%	0%	36%
Don't know	8%	14%	6%	0%	25%	14%	8%	0%	10%	0%	7%
N	37	7	18	7	4	7	13	13	21	2	14

* N is the number of respondents.

Exhibit E.41
CPP Events Took Action

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES2B. For how many of the CPP events were you able to reduce your energy usage?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
0	9%	14%	7%	0%	25%	0%	0%	17%	0%	0%	25%
1-3	30%	43%	21%	43%	25%	17%	36%	33%	37%	0%	25%
4-6	42%	29%	57%	29%	25%	50%	36%	42%	58%	0%	25%
7-9	15%	14%	14%	14%	25%	33%	18%	8%	5%	50%	25%
10-12	3%	0%	0%	14%	0%	0%	9%	0%	0%	50%	0%
N	33	7	14	7	4	6	11	12	19	2	12

* N is the number of respondents.

Exhibit E.42
DBP Events Called

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES3. Thinking back over the summer, how many events would you say were called for the DBP Program?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
0	7%	0%	13%	8%	0%	12%	6%	0%	11%	6%	0%
1	17%	33%	6%	31%	9%	12%	28%	11%	56%	6%	25%
2	33%	50%	38%	15%	36%	24%	50%	11%	11%	39%	25%
3	26%	17%	31%	23%	27%	35%	11%	44%	0%	36%	0%
4	4%	0%	6%	8%	0%	6%	0%	11%	0%	3%	25%
5	4%	0%	0%	0%	18%	0%	6%	11%	11%	3%	0%
Don't know	9%	0%	6%	15%	9%	12%	0%	11%	11%	6%	25%
N	46	6	16	13	11	17	18	9	9	33	4

* N is the number of respondents.

Exhibit E.43
DBP Events Expected

ES4. Were there more, less, or about as many DBP events as you expected?	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
More than expected	4%	0%	3%	0%	14%	6%	2%	6%	4%	1%	17%
About what was expected	33%	31%	36%	38%	19%	33%	33%	31%	21%	34%	50%
Fewer than expected	56%	69%	55%	47%	62%	56%	59%	50%	63%	57%	33%
Don't know	8%	0%	6%	15%	5%	6%	6%	13%	13%	7%	0%
N	104	16	33	34	21	36	49	16	24	68	12

* N is the number of respondents.

Exhibit E.44
DBP Events Bid

ES5. For how many of those DBP events did you submit a bid?	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
0	67%	100%	62%	50%	70%	77%	65%	50%	86%	62%	67%
1	23%	0%	31%	40%	10%	15%	24%	38%	14%	28%	0%
2	8%	0%	0%	10%	20%	8%	12%	0%	0%	10%	0%
3	3%	0%	8%	0%	0%	0%	0%	13%	0%	0%	33%
N	39	6	13	10	10	13	17	8	7	29	3

* N is the number of respondents.

Exhibit E.45
DBP Events Took Action

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES6. For how many of those DBP events did you reduce your energy usage?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
0	49%	50%	46%	30%	70%	38%	65%	38%	71%	45%	33%
1	28%	17%	38%	40%	10%	31%	24%	38%	29%	31%	0%
2	13%	17%	0%	20%	20%	15%	12%	0%	0%	14%	33%
3	8%	17%	15%	0%	0%	8%	0%	25%	0%	7%	33%
4	3%	0%	0%	10%	0%	8%	0%	0%	0%	3%	0%
N	39	6	13	10	10	13	17	8	7	29	3

* N is the number of respondents.

Exhibit E.46
Reasons For Not Taking Action

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES7. What were the main reasons you did not reduce your energy usage for some of these events?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Operation was already shut down	2%	17%	0%	0%	0%	0%	6%	0%	0%	5%	0%	0%	4%
Could not respond in time	20%	17%	13%	44%	9%	10%	22%	27%	27%	24%	0%	21%	19%
Not available to bid that hour	2%	0%	7%	0%	0%	0%	6%	0%	9%	0%	0%	7%	0%
Could not reduce load on that day	44%	50%	40%	56%	36%	40%	39%	55%	45%	38%	56%	57%	37%
System issue/no password	10%	17%	13%	0%	9%	20%	11%	0%	9%	14%	0%	0%	15%
Was not a mandatory reduction	7%	0%	13%	0%	9%	0%	11%	9%	9%	10%	0%	0%	11%
Person in charge of bidding was not there	7%	0%	13%	0%	9%	20%	0%	9%	0%	5%	22%	0%	11%
Other	10%	0%	7%	0%	27%	10%	11%	0%	0%	10%	22%	14%	7%
N	41	6	15	9	11	10	18	11	11	21	9	14	27

* N is the number of respondents.

Exhibit E.47
Prepared for Reductions

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES8. How well prepared was your organization to manage the demand reductions called for by your utility's Demand Response programs this summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very well prepared	38%	39%	46%	32%	33%	39%	30%	50%	47%	34%	33%	49%	35%
Somewhat prepared	48%	43%	40%	59%	50%	41%	59%	39%	40%	53%	50%	46%	49%
Not at all prepared	12%	9%	15%	7%	17%	17%	8%	11%	12%	11%	13%	5%	13%
Don't know	2%	9%	0%	2%	0%	2%	3%	0%	2%	1%	4%	0%	3%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.48
Reasons Not Prepared

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES8A. Why was your organization only somewhat or not at all prepared to manage the demand reductions?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Have other priorities	27%	33%	35%	22%	18%	20%	24%	43%	18%	28%	33%	26%	26%
Not enough notice	16%	17%	12%	15%	18%	16%	17%	7%	18%	11%	27%	26%	14%
Difficult for us to shed much load	22%	33%	19%	22%	18%	16%	24%	29%	23%	20%	27%	21%	21%
We have a load reduction plan in place	13%	8%	4%	19%	24%	12%	17%	0%	9%	20%	0%	5%	15%
Have trouble using the system	18%	8%	27%	15%	18%	32%	10%	21%	18%	17%	20%	16%	18%
Other	5%	0%	8%	4%	6%	4%	5%	7%	9%	4%	0%	11%	5%
Don't know	1%	0%	0%	4%	0%	0%	2%	0%	5%	0%	0%	0%	2%
N	83	12	26	27	17	25	41	14	22	46	15	19	66

* N is the number of respondents.

Exhibit E.49
Level of Assistance

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES9. How would you characterize the level of assistance you received in the development of load reduction options/strategies for this facility?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
As much support as needed	70%	78%	73%	63%	67%	66%	70%	75%	70%	70%	71%	78%	66%
Some support, but not enough	21%	13%	19%	24%	29%	22%	21%	18%	21%	21%	21%	16%	24%
No support	7%	9%	6%	10%	4%	7%	8%	7%	9%	6%	8%	5%	8%
Don't know	1%	0%	2%	2%	0%	5%	0%	0%	0%	3%	0%	0%	2%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.50
Additional Support

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES10. What additional support would you have found helpful in enabling you to reduce your demand?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Nothing	18%	17%	7%	20%	33%	20%	18%	17%	20%	22%	0%	0%	22%
Specific instructions on how to reduce load	18%	33%	40%	0%	0%	33%	14%	0%	20%	17%	14%	10%	19%
More information about program	13%	0%	20%	20%	0%	7%	9%	33%	13%	9%	29%	20%	11%
Install meters to monitor our demand	7%	0%	13%	7%	0%	0%	14%	0%	13%	4%	0%	10%	5%
More warning before an event	9%	17%	0%	0%	33%	0%	18%	0%	13%	9%	0%	10%	8%
Provide tutorial of the bidding system	13%	0%	20%	13%	11%	7%	18%	17%	13%	17%	0%	10%	14%
Other	13%	33%	7%	13%	11%	20%	5%	17%	7%	17%	14%	10%	16%
Don't know	16%	0%	7%	27%	22%	20%	14%	17%	7%	13%	43%	30%	14%
N	45	6	15	15	9	15	22	6	15	23	7	10	37

* N is the number of respondents.

Exhibit E.51
Technical Assistance Awareness

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES11. Are you familiar with the Technical Assistance Incentive available to CPP and DBP program participants?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very familiar	17%	17%	17%	15%	17%	17%	16%	18%	14%	20%	13%	14%	17%
Somewhat familiar	36%	30%	35%	44%	29%	32%	38%	32%	44%	33%	29%	35%	36%
Not at all familiar	47%	52%	48%	41%	50%	51%	44%	50%	40%	47%	58%	49%	47%
Don't know	1%	0%	0%	0%	4%	0%	2%	0%	2%	0%	0%	3%	0%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

Exhibit E.52
Technical Assistance Usage

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES11A. Did you utilize the technical assistance incentive?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	23%	23%	33%	20%	9%	19%	22%	33%	26%	20%	30%	25%	22%
No	74%	77%	63%	76%	91%	76%	78%	60%	70%	78%	70%	70%	76%
Don't know	3%	0%	4%	4%	0%	5%	0%	7%	4%	3%	0%	5%	2%
N	77	13	27	25	11	21	36	15	27	40	10	20	58

* N is the number of respondents.

Exhibit E.53
Reasons Did Not Use Technical Assistance

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES11B. Why didn't you utilize the technical assistance incentive?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Did not need it	53%	44%	47%	61%	50%	44%	54%	67%	59%	58%	14%	54%	53%
Did not have time	13%	22%	18%	6%	10%	13%	19%	0%	18%	6%	29%	15%	12%
Was not aware in time	9%	11%	6%	11%	10%	6%	8%	11%	6%	10%	14%	0%	12%
Other	15%	22%	18%	6%	20%	19%	15%	0%	12%	13%	29%	23%	12%
Don't know	11%	0%	12%	17%	10%	19%	4%	22%	6%	13%	14%	8%	12%
N	55	9	17	18	10	16	26	9	17	31	7	13	43

* N is the number of respondents.

Exhibit E.54
Significance of Good Citizen

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES12A. How significant is **being a good corporate citizen** to your decision to participate in the demand response program for this location?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
1 - Insignificant	4%	4%	2%	5%	8%	5%	5%	4%	5%	4%	4%	0%	6%
2	5%	0%	2%	5%	17%	2%	7%	7%	7%	4%	4%	3%	6%
3	18%	17%	13%	27%	17%	17%	23%	11%	21%	20%	8%	16%	18%
4	34%	39%	38%	29%	33%	29%	41%	36%	28%	37%	38%	32%	35%
5 - Extremely significant	38%	39%	46%	34%	25%	46%	25%	43%	40%	34%	46%	49%	36%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.55
Significance of Avoiding Blackouts

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES12B. How significant is **avoiding rolling blackouts** to your decision to participate in the demand response program for this location?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
1 - Insignificant	4%	4%	4%	2%	4%	2%	2%	11%	5%	4%	0%	0%	5%
2	7%	0%	6%	7%	13%	2%	8%	11%	5%	7%	8%	5%	7%
3	15%	22%	13%	10%	25%	10%	20%	14%	21%	11%	17%	16%	14%
4	18%	22%	13%	17%	25%	20%	21%	11%	23%	14%	17%	19%	17%
5 - Extremely significant	57%	52%	65%	63%	33%	66%	49%	54%	47%	63%	58%	59%	57%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.56
Significance of Bill Savings

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES12C. How significant is **the amount of potential bill savings** to your decision to participate in the demand response program for this location?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
1 - Insignificant	4%	4%	0%	7%	8%	5%	5%	4%	2%	4%	8%	0%	6%
2	6%	9%	4%	7%	4%	7%	5%	4%	7%	3%	13%	3%	7%
3	18%	9%	15%	24%	25%	15%	23%	18%	23%	19%	8%	16%	18%
4	20%	17%	27%	12%	21%	22%	18%	21%	16%	21%	21%	14%	21%
5 - Extremely significant	52%	61%	54%	49%	42%	51%	49%	54%	51%	53%	50%	68%	48%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.57
Significance of No Disruption

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES12D. How significant is **being able to participate in the program without significantly affecting your business operations** to your decision to participate in the demand response program for this location?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
1 - Insignificant	4%	0%	8%	0%	4%	7%	0%	7%	0%	7%	0%	0%	5%
2	1%	0%	0%	0%	4%	0%	2%	0%	0%	1%	0%	0%	1%
3	16%	26%	10%	24%	4%	22%	13%	14%	9%	19%	21%	16%	15%
4	20%	17%	27%	10%	21%	22%	21%	14%	23%	20%	13%	24%	19%
5 - Extremely significant	60%	57%	54%	66%	67%	49%	64%	64%	67%	53%	67%	59%	60%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.58
Significance of Occupant Comfort

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES13A. How significant is **the effect on occupant comfort** as a concern about demand response program participation at this location?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
1 - Insignificant	18%	9%	23%	15%	21%	12%	20%	25%	19%	17%	17%	19%	18%
2	14%	22%	10%	17%	8%	2%	23%	11%	19%	10%	17%	24%	10%
3	28%	35%	19%	34%	25%	24%	36%	11%	35%	29%	13%	24%	29%
4	12%	17%	10%	10%	17%	20%	10%	7%	9%	11%	21%	5%	15%
5 - Extremely significant	27%	13%	38%	24%	25%	41%	11%	46%	19%	31%	29%	24%	27%
Don't know	1%	4%	0%	0%	4%	0%	0%	0%	0%	1%	4%	3%	1%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.59
Significance of Productivity

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES13B. How significant is **the effect on products or productivity** as a concern about demand response program participation at this location?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
1 - Insignificant	9%	0%	23%	2%	0%	7%	7%	18%	12%	7%	8%	16%	8%
2	3%	4%	2%	2%	4%	5%	2%	4%	0%	6%	0%	0%	4%
3	13%	22%	13%	5%	21%	20%	11%	7%	14%	10%	21%	22%	11%
4	18%	26%	13%	27%	8%	12%	23%	14%	16%	21%	13%	19%	17%
5 - Extremely significant	56%	43%	50%	63%	67%	56%	57%	57%	58%	54%	58%	43%	60%
Don't know	1%	4%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.60
Significance of Bill Savings

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES13C. How significant is **the amount of potential bill savings** as a concern about demand response program participation at this location?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
1 - Insignificant	4%	4%	6%	5%	0%	2%	5%	7%	5%	4%	4%	5%	4%
2	13%	17%	13%	10%	17%	17%	10%	14%	16%	11%	13%	14%	13%
3	18%	17%	15%	20%	21%	15%	21%	18%	19%	14%	25%	19%	16%
4	26%	17%	29%	29%	25%	34%	21%	25%	21%	29%	29%	16%	29%
5 - Extremely significant	38%	43%	35%	37%	38%	32%	41%	36%	37%	41%	29%	43%	38%
Don't know	1%	0%	2%	0%	0%	0%	2%	0%	2%	0%	0%	3%	0%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.61
Significance of Peak Load Reduction

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES13D. How significant is **the inability to reduce peak loads** as a concern about demand response program participation at this location?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
1 - Insignificant	15%	4%	21%	10%	21%	17%	11%	18%	16%	11%	21%	16%	14%
2	6%	9%	2%	7%	8%	2%	5%	14%	2%	9%	4%	3%	7%
3	25%	26%	21%	34%	17%	24%	25%	29%	23%	23%	33%	27%	25%
4	26%	26%	29%	20%	29%	27%	34%	7%	44%	21%	8%	30%	25%
5 - Extremely significant	28%	30%	27%	29%	25%	29%	25%	32%	14%	34%	33%	24%	28%
Don't know	1%	4%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	1%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.62
Satisfaction with Notification

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES14A. How satisfied were you with the process by which you were notified about the DR event?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very satisfied	61%	70%	65%	59%	46%	51%	62%	68%	70%	57%	54%	73%	55%
Somewhat satisfied	31%	22%	27%	34%	42%	41%	26%	25%	23%	31%	42%	24%	35%
Somewhat dissatisfied	3%	4%	2%	2%	4%	2%	5%	0%	5%	3%	0%	0%	4%
Very dissatisfied	4%	4%	4%	5%	4%	2%	7%	4%	0%	7%	4%	3%	5%
Don't know	1%	0%	2%	0%	4%	2%	0%	4%	2%	1%	0%	0%	2%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.63
Satisfaction with Timeframe

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES14B. How satisfied were you with the amount of advanced notification?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very satisfied	36%	30%	56%	27%	17%	22%	34%	54%	51%	27%	38%	62%	28%
Somewhat satisfied	45%	52%	33%	46%	58%	63%	34%	43%	28%	51%	54%	27%	51%
Somewhat dissatisfied	10%	4%	8%	12%	17%	5%	20%	0%	14%	10%	4%	5%	12%
Very dissatisfied	8%	13%	0%	15%	8%	7%	11%	4%	7%	10%	4%	5%	9%
Don't know	1%	0%	2%	0%	0%	2%	0%	0%	0%	1%	0%	0%	1%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.64
CPP Satisfaction with Number of Events

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES14C1. How satisfied were you with the number of CPP events called?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	49%	29%	67%	43%	25%	43%	54%	54%	48%	50%	50%
Somewhat satisfied	41%	57%	33%	43%	50%	57%	38%	31%	43%	0%	43%
Somewhat dissatisfied	5%	0%	0%	0%	25%	0%	0%	8%	5%	0%	7%
Very dissatisfied	3%	14%	0%	0%	0%	0%	8%	0%	0%	50%	0%
Don't know	3%	0%	0%	14%	0%	0%	0%	8%	5%	0%	0%
N	37	7	18	7	4	7	13	13	21	2	14

* N is the number of respondents.

Exhibit E.65
DBP Satisfaction with Number of Events

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES14C2. How satisfied were you with the number of DBP events called?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	23%	25%	24%	26%	14%	22%	16%	38%	13%	24%	42%
Somewhat satisfied	55%	56%	48%	59%	57%	61%	61%	31%	54%	60%	25%
Somewhat dissatisfied	15%	13%	18%	12%	19%	14%	16%	19%	25%	12%	17%
Very dissatisfied	2%	6%	3%	0%	0%	0%	4%	0%	4%	1%	0%
Don't know	5%	0%	6%	3%	10%	3%	2%	13%	4%	3%	17%
N	104	16	33	34	21	36	49	16	24	68	12

* N is the number of respondents.

Exhibit E.66
CPP Satisfaction with Duration of Events

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES14D1. How satisfied were you with the duration of the CPP events called?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	46%	57%	61%	29%	0%	43%	54%	38%	48%	50%	43%
Somewhat satisfied	49%	43%	28%	71%	100%	43%	46%	54%	48%	50%	50%
Somewhat dissatisfied	5%	0%	11%	0%	0%	14%	0%	8%	5%	0%	7%
N	37	7	18	7	4	7	13	13	21	2	14

* N is the number of respondents.

Exhibit E.67
DBP Satisfaction with Duration of Events

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES14D2. How satisfied were you with the duration of the DBP events called?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	31%	25%	45%	35%	5%	28%	27%	50%	17%	32%	50%
Somewhat satisfied	48%	50%	39%	53%	52%	56%	47%	38%	42%	51%	42%
Somewhat dissatisfied	6%	6%	0%	3%	19%	3%	10%	0%	13%	4%	0%
Don't know	15%	19%	15%	9%	24%	14%	16%	13%	29%	12%	8%
N	104	16	33	34	21	36	49	16	24	68	12

* N is the number of respondents.

Exhibit E.68
Satisfaction with Customer Service

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES14E. How satisfied were you with the program-related customer service you received from your utility?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very satisfied	56%	57%	64%	44%	58%	55%	49%	68%	61%	48%	71%	69%	52%
Somewhat satisfied	34%	39%	24%	44%	29%	33%	41%	25%	29%	39%	25%	26%	36%
Somewhat dissatisfied	6%	0%	7%	7%	8%	5%	7%	4%	5%	7%	4%	3%	7%
Very dissatisfied	2%	0%	0%	5%	4%	3%	3%	0%	0%	4%	0%	0%	3%
Don't know	2%	4%	4%	0%	0%	5%	0%	4%	5%	1%	0%	3%	2%
N	134	23	45	41	24	40	59	28	41	69	24	35	103

* N is the number of respondents.

Exhibit E.69
CPP Satisfaction with Rates

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES14F. How satisfied were you with the CPP rates you pay?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	32%	43%	39%	25%	0%	14%	23%	43%	29%	33%	36%
Somewhat satisfied	45%	29%	44%	38%	75%	57%	54%	36%	48%	33%	43%
Somewhat dissatisfied	8%	14%	6%	13%	0%	0%	15%	7%	5%	33%	7%
Very dissatisfied	3%	0%	0%	0%	25%	0%	0%	0%	0%	0%	7%
Don't know	13%	14%	11%	25%	0%	29%	8%	14%	19%	0%	7%
N	38	7	18	8	4	7	13	14	21	3	14

* N is the number of respondents.

Exhibit E.70
CPP Satisfaction with Bill Credit

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES14G1. How satisfied were you with the amount of bill credit for participating in the CPP program?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	31%	33%	39%	14%	25%	0%	25%	46%	35%	0%	29%
Somewhat satisfied	47%	50%	44%	43%	50%	86%	50%	23%	50%	50%	43%
Somewhat dissatisfied	8%	17%	6%	0%	25%	0%	8%	15%	0%	50%	14%
Very dissatisfied	3%	0%	0%	14%	0%	0%	0%	8%	0%	0%	7%
Don't know	11%	0%	11%	29%	0%	14%	17%	8%	15%	0%	7%
N	36	6	18	7	4	7	12	13	20	2	14

* N is the number of respondents.

Exhibit E.71
DBP Satisfaction with Incentives

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES14G2. How satisfied were you with the amount of incentives offered for participating in the DBP program?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	25%	25%	31%	18%	29%	26%	22%	38%	29%	25%	17%
Somewhat satisfied	50%	44%	53%	53%	48%	54%	43%	63%	29%	58%	50%
Somewhat dissatisfied	17%	31%	3%	21%	24%	9%	29%	0%	33%	12%	17%
Very dissatisfied	4%	0%	3%	9%	0%	3%	6%	0%	4%	4%	0%
Don't know	3%	0%	9%	0%	0%	9%	0%	0%	4%	0%	17%
N	103	16	32	34	21	35	49	16	24	67	12

* N is the number of respondents.

Exhibit E.72
CPP Satisfaction

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES15_CPP. Overall, how satisfied are you with your participation in the CPP program this past summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	51%	57%	67%	43%	0%	57%	38%	62%	48%	50%	57%
Somewhat satisfied	43%	43%	28%	57%	75%	43%	54%	38%	48%	50%	36%
Somewhat dissatisfied	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Very dissatisfied	3%	0%	0%	0%	25%	0%	0%	0%	0%	0%	7%
Don't know	3%	0%	6%	0%	0%	0%	8%	0%	5%	0%	0%
N	37	7	18	7	4	7	13	13	21	2	14

* N is the number of respondents.

Exhibit E.73
CPP Satisfaction by Action Taken

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES15_CPP. Overall, how satisfied are you with your participation in the CPP program this past summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Took action											
Very satisfied	53%	50%	71%	50%	0%	57%	42%	63%	50%	50%	63%
Somewhat satisfied	43%	50%	21%	50%	100%	43%	50%	38%	45%	50%	38%
Somewhat dissatisfied	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Very dissatisfied	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Don't know	3%	0%	7%	0%	0%	0%	8%	0%	5%	0%	0%
N	30	6	14	6	3	7	12	8	20	2	8
Did not take action											
Very satisfied	43%	100%	50%	0%	0%	0%	0%	60%	0%	0%	50%
Somewhat satisfied	43%	0%	50%	100%	0%	0%	100%	40%	100%	0%	33%
Somewhat dissatisfied	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Very dissatisfied	14%	0%	0%	0%	100%	0%	0%	0%	0%	0%	17%
N	7	1	4	1	1	0	1	5	1	0	6

* N is the number of respondents.

Exhibit E.74
CPP Reasons for Satisfaction

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES16_CPP. Why do you give that satisfaction rating?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
It is not difficult for us to reduce load	26%	14%	38%	14%	0%	43%	27%	15%	26%	50%	21%
Want more advanced notice	9%	14%	13%	0%	0%	0%	27%	0%	11%	50%	0%
Wish we could cut back more	9%	14%	0%	14%	25%	0%	0%	15%	0%	0%	21%
Good for system-reduce load/avoid blackouts	26%	29%	38%	14%	0%	14%	9%	38%	32%	0%	21%
Did not get much out of the program	11%	0%	0%	29%	50%	29%	9%	8%	5%	0%	21%
Too soon to tell	11%	0%	13%	29%	0%	0%	9%	23%	11%	0%	14%
Website does not always work	3%	0%	6%	0%	0%	0%	9%	0%	5%	0%	0%
Happy with bill savings	3%	14%	0%	0%	0%	0%	9%	0%	5%	0%	0%
Other	6%	14%	0%	0%	25%	14%	9%	0%	11%	0%	0%
N	35	7	16	7	4	7	11	13	19	2	14

* N is the number of respondents.

Exhibit E.75
CPP Reasons for Satisfaction

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES16_CPP. Why do you give that satisfaction rating?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Satisfied Participants											
It is not difficult for us to reduce load	26%	14%	38%	14%	0%	43%	27%	15%	26%	50%	23%
Want more advanced notice	9%	14%	13%	0%	0%	0%	27%	0%	11%	50%	0%
Wish we could cut back more	6%	14%	0%	14%	0%	0%	0%	15%	0%	0%	15%
Good for system-reduce load/avoid blackouts	26%	29%	38%	14%	0%	14%	9%	38%	32%	0%	23%
Did not get much out of the program	12%	0%	0%	29%	67%	29%	9%	8%	5%	0%	23%
Too soon to tell	12%	0%	13%	29%	0%	0%	9%	23%	11%	0%	15%
Website does not always work	3%	0%	6%	0%	0%	0%	9%	0%	5%	0%	0%
Happy with bill savings	3%	14%	0%	0%	0%	0%	9%	0%	5%	0%	0%
Other	6%	14%	0%	0%	33%	14%	9%	0%	11%	0%	0%
N	34	7	16	7	3	7	11	13	19	2	13
Unsatisfied Participants											
Wish we could cut back more	100%	0%	0%	0%	100%	0%	0%	0%	0%	0%	100%
N	1	0	0	0	1	0	0	0	0	0	1

* N is the number of respondents.

Exhibit E.76
CPP Suggestions

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES17_CPP. Do you have any suggestions for improving the CPP program?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Nothing	51%	57%	33%	100%	25%	57%	31%	62%	48%	50%	57%
Want more advanced notice	14%	14%	17%	0%	25%	0%	23%	15%	10%	50%	14%
More technical assistance	5%	0%	11%	0%	0%	0%	8%	8%	5%	0%	7%
Give real time data of demand during event	5%	14%	0%	0%	25%	14%	8%	0%	10%	0%	0%
Increase incentives	8%	29%	0%	0%	25%	0%	15%	0%	5%	50%	7%
Improve website	5%	0%	11%	0%	0%	0%	15%	0%	10%	0%	0%
Other	16%	0%	33%	0%	0%	29%	8%	23%	14%	0%	21%
N	37	7	18	7	4	7	13	13	21	2	14

* N is the number of respondents.

Exhibit E.77
CPP Plan to Participate

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES18_CPP. Do you plan to participate in the CPP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	86%	100%	83%	71%	100%	100%	69%	92%	81%	100%	93%
Don't know	14%	0%	17%	29%	0%	0%	31%	8%	19%	0%	7%
N	37	7	18	7	4	7	13	13	21	2	14

* N is the number of respondents.

Exhibit E.78
CPP Reasons for Participation

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES19_CPP. Why do you plan to participate in the CPP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Not difficult to reduce load	18%	0%	31%	0%	25%	14%	30%	17%	22%	0%	15%
Save money	55%	29%	63%	40%	75%	57%	60%	50%	50%	50%	62%
Good corporate citizen-reduce load/avoid blackouts	27%	14%	31%	40%	25%	43%	10%	33%	22%	0%	38%
Savings are small	9%	14%	6%	0%	25%	0%	20%	0%	6%	50%	8%
Other	18%	43%	6%	40%	0%	29%	10%	25%	28%	0%	8%
N	33	7	16	5	4	7	10	12	18	2	13

* N is the number of respondents.

Exhibit E.79
DBP Satisfaction

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES20_DBP. Overall, how satisfied are you with your participation in the DBP program this past summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Very satisfied	26%	31%	33%	24%	14%	28%	20%	38%	17%	29%	25%
Somewhat satisfied	46%	25%	45%	53%	52%	50%	41%	56%	42%	46%	58%
Somewhat dissatisfied	23%	25%	21%	21%	29%	19%	33%	6%	42%	19%	8%
Very dissatisfied	3%	6%	0%	3%	5%	0%	6%	0%	0%	4%	0%
Don't know	2%	13%	0%	0%	0%	3%	0%	0%	0%	1%	8%
N	104	16	33	34	21	36	49	16	24	68	12

* N is the number of respondents.

Exhibit E.80
DBP Satisfaction by Placed Bid

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES20_DBP. Overall, how satisfied are you with your participation in the DBP program this past summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Placed a bid											
Very satisfied	48%	100%	57%	30%	50%	38%	44%	60%	0%	47%	50%
Somewhat satisfied	39%	0%	29%	60%	25%	50%	33%	40%	0%	35%	50%
Somewhat dissatisfied	9%	0%	14%	10%	0%	13%	11%	0%	0%	12%	0%
Very dissatisfied	4%	0%	0%	0%	25%	0%	11%	0%	0%	6%	0%
N	23	2	7	10	4	8	9	5	0	17	6
Did not place a bid											
Very satisfied	20%	21%	27%	21%	6%	25%	15%	27%	17%	24%	0%
Somewhat satisfied	48%	29%	50%	50%	59%	50%	43%	64%	42%	49%	67%
Somewhat dissatisfied	27%	29%	23%	25%	35%	21%	38%	9%	42%	22%	17%
Very dissatisfied	2%	7%	0%	4%	0%	0%	5%	0%	0%	4%	0%
Don't know	2%	14%	0%	0%	0%	4%	0%	0%	0%	2%	17%
N	81	14	26	24	17	28	40	11	24	51	6

* N is the number of respondents.

Exhibit E.81
DBP Satisfaction by Took Action

ES20_DBP. Overall, how satisfied are you with your participation in the DBP program this past summer?	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Took action											
Very satisfied	42%	67%	50%	29%	33%	36%	39%	56%	67%	39%	33%
Somewhat satisfied	42%	17%	36%	53%	50%	43%	39%	44%	17%	43%	56%
Somewhat dissatisfied	14%	17%	14%	18%	0%	21%	17%	0%	17%	14%	11%
Very dissatisfied	2%	0%	0%	0%	17%	0%	6%	0%	0%	4%	0%
N	43	6	14	17	6	14	18	9	6	28	9
Did not take action											
Very satisfied	15%	10%	21%	18%	7%	23%	10%	14%	0%	23%	0%
Somewhat satisfied	49%	30%	53%	53%	53%	55%	42%	71%	50%	48%	67%
Somewhat dissatisfied	30%	30%	26%	24%	40%	18%	42%	14%	50%	23%	0%
Very dissatisfied	3%	10%	0%	6%	0%	0%	6%	0%	0%	5%	0%
Don't know	3%	20%	0%	0%	0%	5%	0%	0%	0%	3%	33%
N	61	10	19	17	15	22	31	7	18	40	3

* N is the number of respondents.

Exhibit E.82
DBP Reasons for Satisfaction

ES21_DBP. Why do you give that satisfaction rating?	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Opportunity to save money	7%	7%	9%	3%	10%	9%	4%	7%	0%	11%	0%
Good for system-reduce load/avoid blackouts	5%	14%	6%	3%	0%	9%	2%	0%	0%	5%	18%
Want more advanced notice	14%	14%	12%	16%	14%	17%	17%	0%	9%	18%	0%
Did not save as much as expected	10%	0%	12%	10%	14%	3%	17%	7%	22%	6%	9%
Wish we could cut back more	14%	7%	12%	16%	19%	9%	11%	33%	4%	12%	45%
System was difficult to use	5%	7%	9%	0%	5%	6%	4%	7%	0%	8%	0%
Did not get a chance to participate/few events	18%	21%	12%	26%	14%	11%	28%	7%	39%	14%	0%
Did not get much out of the program	9%	7%	15%	10%	0%	14%	6%	7%	13%	9%	0%
The program ran smoothly	16%	14%	24%	13%	10%	23%	9%	27%	9%	17%	27%
Like that the program is optional - no penalties	4%	7%	0%	3%	10%	6%	2%	7%	4%	5%	0%
Want more incentives	8%	0%	6%	16%	5%	9%	9%	7%	9%	5%	27%
Other	5%	7%	6%	3%	5%	3%	6%	7%	13%	3%	0%
Don't know	6%	0%	3%	10%	10%	9%	6%	0%	0%	8%	9%
N	99	14	33	31	21	35	47	15	23	65	11

* N is the number of respondents.

Exhibit E.83
DBP Reasons for Satisfaction

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES21_DBP. Why do you give that satisfaction rating?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Satisfied Participants											
Opportunity to save money	10%	11%	12%	4%	14%	11%	7%	7%	0%	14%	0%
Good for system-reduce load/avoid blackouts	7%	22%	8%	4%	0%	11%	4%	0%	0%	6%	20%
Want more advanced notice	7%	0%	12%	9%	0%	14%	4%	0%	0%	10%	0%
Did not save as much as expected	8%	0%	12%	4%	14%	4%	14%	7%	23%	4%	10%
Wish we could cut back more	14%	11%	8%	17%	21%	7%	11%	29%	8%	10%	40%
System was difficult to use	3%	0%	8%	0%	0%	0%	4%	7%	0%	4%	0%
Did not get a chance to participate/few events	14%	11%	8%	26%	7%	11%	21%	7%	15%	16%	0%
Did not get much out of the program	10%	11%	15%	9%	0%	14%	7%	7%	15%	10%	0%
The program ran smoothly	22%	22%	31%	17%	14%	29%	14%	29%	15%	22%	30%
Like that the program is optional - no penalties	6%	11%	0%	4%	14%	7%	4%	7%	8%	6%	0%
Want more incentives	7%	0%	8%	9%	7%	11%	4%	7%	8%	2%	30%
Other	7%	11%	8%	4%	7%	4%	11%	7%	23%	4%	0%
Don't know	8%	0%	4%	13%	14%	11%	11%	0%	0%	10%	10%
N	72	9	26	23	14	28	28	14	13	49	10
Unsatisfied Participants											
Want more advanced notice	33%	40%	14%	38%	43%	29%	37%	0%	20%	44%	0%
Did not save as much as expected	15%	0%	14%	25%	14%	0%	21%	0%	20%	13%	0%
Wish we could cut back more	15%	0%	29%	13%	14%	14%	11%	100%	0%	19%	100%
System was difficult to use	11%	20%	14%	0%	14%	29%	5%	0%	0%	19%	0%
Did not get a chance to participate/few events	30%	40%	29%	25%	29%	14%	37%	0%	70%	6%	0%
Did not get much out of the program	7%	0%	14%	13%	0%	14%	5%	0%	10%	6%	0%
Want more incentives	11%	0%	0%	38%	0%	0%	16%	0%	10%	13%	0%
N	27	5	7	8	7	7	19	1	10	16	1

* N is the number of respondents.

Exhibit E.84
DBP Suggestions

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES22_DBP. Do you have any suggestions for improving the DBP program?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Nothing	61%	63%	70%	44%	71%	61%	57%	75%	67%	56%	75%
Give more warning before an event	18%	19%	12%	26%	14%	17%	22%	6%	17%	19%	17%
Increase incentives	10%	6%	3%	18%	10%	3%	16%	0%	13%	9%	8%
Follow up after event	2%	0%	3%	0%	5%	3%	2%	0%	0%	3%	0%
Notify more than one person	1%	0%	0%	0%	5%	3%	0%	0%	0%	1%	0%
Reduce load shed requirement	1%	0%	3%	0%	0%	3%	0%	0%	0%	1%	0%
More technical assistance	1%	0%	0%	3%	0%	0%	2%	0%	0%	1%	0%
Other	11%	13%	9%	18%	0%	14%	6%	19%	8%	12%	8%
N	104	16	33	34	21	36	49	16	24	68	12

* N is the number of respondents.

Exhibit E.85
DBP Plan to Participate

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES23_DBP. Do you plan to participate in the DBP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Yes	83%	94%	85%	85%	67%	81%	86%	75%	79%	84%	83%
No	10%	6%	9%	3%	24%	11%	8%	13%	8%	10%	8%
Don't know	8%	0%	6%	12%	10%	8%	6%	13%	13%	6%	8%
N	104	16	33	34	21	36	49	16	24	68	12

* N is the number of respondents.

Exhibit E.86
DBP Plan to Participate by Placed Bid

ES23_DBP. Do you plan to participate in the DBP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
Placed a bid											
Yes	91%	100%	86%	100%	75%	88%	89%	100%	0%	88%	100%
No	9%	0%	14%	0%	25%	13%	11%	0%	0%	12%	0%
N	23	2	7	10	4	8	9	5	0	17	6
Did not place a bid											
Yes	80%	93%	85%	79%	65%	79%	85%	64%	79%	82%	67%
No	10%	7%	8%	4%	24%	11%	8%	18%	8%	10%	17%
Don't know	10%	0%	8%	17%	12%	11%	8%	18%	13%	8%	17%
N	81	14	26	24	17	28	40	11	24	51	6

* N is the number of respondents.

Exhibit E.87
DBP Plan to Participate by Took Action

ES23_DBP. Do you plan to participate in the DBP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
Took action											
Yes	93%	100%	93%	94%	83%	93%	89%	100%	83%	93%	100%
No	5%	0%	7%	0%	17%	7%	6%	0%	0%	7%	0%
Don't know	2%	0%	0%	6%	0%	0%	6%	0%	17%	0%	0%
N	43	6	14	17	6	14	18	9	6	28	9
Did not take action											
Yes	75%	90%	79%	76%	60%	73%	84%	43%	78%	78%	33%
No	13%	10%	11%	6%	27%	14%	10%	29%	11%	13%	33%
Don't know	11%	0%	11%	18%	13%	14%	6%	29%	11%	10%	33%
N	61	10	19	17	15	22	31	7	18	40	3

* N is the number of respondents.

Exhibit E.88
DBP Reasons for Participation

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES24_DBP. Why do you/don't you plan to participate in the DBP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Good corporate citizen-reduce load/avoid blackouts	24%	31%	23%	20%	26%	30%	13%	46%	23%	19%	55%
Opportunity to save money	26%	25%	26%	30%	21%	30%	21%	23%	9%	35%	9%
Good program	14%	0%	23%	10%	16%	18%	11%	8%	23%	8%	27%
Not difficult for us to participate	7%	6%	6%	10%	5%	6%	6%	15%	5%	8%	9%
Not happy with the program	7%	0%	6%	7%	16%	6%	9%	8%	0%	11%	0%
Did not get much out of the program	6%	6%	6%	3%	11%	6%	9%	0%	14%	3%	9%
Will be easier for us to participate next year	7%	13%	3%	13%	0%	0%	15%	0%	5%	8%	9%
If we can participate, we will	18%	13%	16%	20%	21%	15%	17%	31%	9%	22%	9%
Other	8%	19%	6%	3%	11%	6%	11%	8%	18%	6%	0%
Don't know	1%	0%	3%	0%	0%	3%	0%	0%	0%	2%	0%
N	96	16	31	30	19	33	47	13	22	63	11

* N is the number of respondents.

Exhibit E.89
DBP Reasons for Participation

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES24_DBP. Why do you/don't you plan to participate in the DBP program next summer?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Plan to participate											
Good corporate citizen-reduce load/avoid blackouts	27%	33%	25%	21%	36%	34%	14%	55%	26%	21%	60%
Opportunity to save money	29%	27%	29%	32%	29%	34%	24%	27%	11%	39%	10%
Good program	15%	0%	25%	11%	21%	21%	12%	9%	26%	9%	30%
Not difficult for us to participate	8%	7%	7%	11%	7%	7%	7%	18%	5%	9%	10%
Not happy with the program	4%	0%	4%	4%	7%	3%	5%	0%	0%	5%	0%
Did not get much out of the program	1%	0%	4%	0%	0%	0%	2%	0%	5%	0%	0%
Will be easier for us to participate next year	8%	13%	4%	14%	0%	0%	17%	0%	5%	9%	10%
If we can participate, we will	20%	13%	18%	21%	29%	17%	19%	36%	11%	25%	10%
Other	7%	20%	7%	4%	0%	7%	10%	0%	16%	5%	0%
Don't know	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
N	85	15	28	28	14	29	42	11	19	56	10
Don't plan to participate											
Not happy with the program	40%	0%	33%	100%	40%	25%	50%	50%	0%	57%	0%
Did not get much out of the program	40%	100%	33%	0%	40%	50%	50%	0%	50%	29%	100%
Other	20%	0%	0%	0%	40%	0%	25%	50%	50%	14%	0%
Don't know	10%	0%	33%	0%	0%	25%	0%	0%	0%	14%	0%
N	10	1	3	1	5	4	4	2	2	7	1

* N is the number of respondents.

Exhibit E.90
Participation in Other Program

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES25. Do you plan to participate in another demand response program or tarriff?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Yes	31%	30%	28%	39%	26%	36%	31%	25%	23%	38%	25%	22%	35%
No	44%	43%	43%	44%	48%	41%	46%	46%	49%	44%	38%	38%	46%
Don't know	24%	26%	30%	17%	26%	23%	23%	29%	28%	18%	38%	41%	19%
N	135	23	47	41	23	39	61	28	43	68	24	37	102

* N is the number of respondents.

Exhibit E.91
Other Demand Response Programs

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES25A. Which other demand response program do you plan to participate in?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
BIP	2%	0%	0%	6%	0%	0%	5%	0%	0%	4%	0%	0%	3%
I-6/AL-TOU-CP/NON-FIRM	9%	0%	15%	6%	17%	21%	5%	0%	0%	15%	0%	0%	11%
RBRP	5%	0%	8%	6%	0%	7%	0%	0%	0%	0%	33%	0%	6%
CPP	2%	13%	0%	0%	0%	0%	0%	0%	9%	0%	0%	11%	0%
DBP	12%	13%	15%	13%	0%	14%	15%	0%	18%	8%	17%	0%	14%
Any program offered	14%	0%	31%	13%	0%	21%	10%	14%	9%	19%	0%	11%	17%
Other	9%	13%	8%	0%	33%	7%	15%	0%	18%	0%	33%	0%	11%
Don't know	51%	63%	38%	56%	50%	43%	50%	86%	45%	54%	50%	78%	44%
N	43	8	13	16	6	14	20	7	11	26	6	9	36

* N is the number of respondents.

Exhibit E.92
Reasons for Switching Programs

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES25B. Why do you plan to switch to the other demand response program?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Cost savings	75%	0%	67%	100%	0%	100%	50%	100%	50%	100%	0%	50%	100%
Easier to participate in	25%	0%	33%	0%	0%	100%	0%	0%	0%	50%	0%	0%	50%
Don't know	25%	0%	33%	0%	0%	0%	50%	0%	50%	0%	0%	50%	0%
N	4	0	3	1	0	1	2	1	2	2	0	2	2

* N is the number of respondents.

Exhibit E.93
CPP Change in Demand Reduction

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES26A. For next summer, do you think your demand reduction for CPP program events will increase, decrease, or stay about the same?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Increase	15%	14%	13%	20%	25%	0%	20%	17%	22%	0%	8%
Decrease	3%	14%	0%	0%	0%	0%	10%	0%	0%	50%	0%
Stay about the same	79%	71%	88%	80%	50%	100%	70%	75%	78%	50%	85%
Don't know	3%	0%	0%	0%	25%	0%	0%	8%	0%	0%	8%
N	33	7	16	5	4	7	10	12	18	2	13

* N is the number of respondents.

Exhibit E.94
DBP Changes in Demand Reduction

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY										
ES26B. For next summer, do you think your demand reduction for DBP program events will increase, decrease, or stay about the same?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E
Increase	27%	47%	24%	27%	14%	13%	28%	42%	10%	33%	30%
Decrease	2%	7%	3%	0%	0%	7%	0%	0%	0%	3%	0%
Stay about the same	64%	47%	59%	67%	86%	77%	63%	50%	75%	60%	60%
Don't know	7%	0%	14%	7%	0%	3%	9%	8%	15%	3%	10%
N	88	15	29	30	14	30	43	12	20	58	10

* N is the number of respondents.

Exhibit E.95
Knowledge

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
ES30. As a result of your program experience this past summer, how much more knowledgeable would you say you are about managing your energy usage at times of peak demand?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Much more knowledgeable	15%	13%	15%	22%	4%	7%	15%	21%	16%	13%	17%	19%	13%
Somewhat more knowledgeable	62%	74%	67%	51%	63%	73%	52%	71%	53%	66%	67%	59%	63%
No more knowledgeable	23%	13%	19%	27%	33%	20%	33%	7%	30%	21%	17%	22%	24%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.96
Monitor Electricity Markets

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
EM3. How closely does your organization monitor and analyze electricity markets and prices?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very closely	36%	30%	25%	41%	50%	32%	33%	43%	30%	41%	29%	22%	40%
Somewhat closely	39%	48%	40%	37%	38%	41%	43%	32%	42%	33%	54%	54%	36%
Not very closely	23%	22%	35%	20%	8%	24%	25%	21%	26%	24%	17%	22%	23%
Don't know	1%	0%	0%	2%	4%	2%	0%	4%	2%	1%	0%	3%	1%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.97
California's Power Supplies

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
EM5. In your organization's view, how likely is it that California's power supplies will be inadequate to meet expected power demand over the next three years?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very likely	16%	17%	10%	20%	17%	20%	18%	7%	14%	14%	25%	19%	15%
Somewhat likely	40%	57%	31%	37%	50%	32%	43%	43%	37%	43%	38%	41%	39%
Somewhat unlikely	27%	13%	35%	27%	25%	32%	30%	18%	35%	21%	29%	22%	29%
Very unlikely	11%	9%	19%	10%	0%	12%	7%	21%	7%	16%	4%	14%	10%
Refused	1%	0%	0%	0%	4%	0%	2%	0%	2%	0%	0%	0%	1%
Don't know	5%	4%	4%	7%	4%	5%	2%	11%	5%	6%	4%	5%	6%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.98
Concern Over Energy Costs

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
EM7. How concerned is your organization about energy costs relative to other costs of running your business?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Very concerned	71%	78%	63%	68%	83%	71%	70%	64%	70%	71%	71%	68%	72%
Somewhat concerned	26%	17%	35%	27%	13%	22%	28%	32%	26%	26%	25%	27%	25%
Relatively unconcerned	3%	4%	2%	2%	4%	7%	2%	0%	5%	3%	0%	3%	3%
Don't know	1%	0%	0%	2%	0%	0%	0%	4%	0%	0%	4%	3%	0%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.99
Energy Costs

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
EC5. What percent of your organization's total annual operating costs do energy costs represent?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Less than 1 percent	1%	0%	0%	0%	4%	2%	0%	0%	0%	1%	0%	0%	1%
1 to 4 percent	15%	13%	15%	17%	13%	2%	18%	29%	14%	14%	17%	16%	13%
5 to 10 percent	22%	13%	27%	17%	25%	20%	21%	29%	28%	20%	17%	16%	24%
11 to 25 percent	25%	39%	13%	32%	25%	17%	33%	18%	23%	30%	13%	22%	26%
Over 25 percent	14%	13%	17%	12%	13%	24%	10%	7%	14%	11%	21%	24%	12%
Refused	2%	0%	6%	0%	0%	0%	5%	0%	5%	1%	0%	3%	2%
Don't know	22%	22%	23%	22%	21%	34%	13%	18%	16%	21%	33%	19%	22%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.100
Largest End Use

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
EC9A. Which of the following is the largest end use in terms of electricity consumption for this facility?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Lighting	8%	4%	8%	7%	13%	15%	2%	14%	12%	7%	4%	5%	9%
HVAC	31%	26%	35%	29%	33%	41%	18%	46%	28%	34%	29%	32%	32%
Continous processing	27%	35%	19%	29%	33%	7%	51%	7%	30%	31%	8%	19%	30%
Batch processing	7%	9%	8%	5%	4%	0%	13%	4%	12%	6%	4%	8%	7%
Refrigeration	12%	9%	13%	20%	4%	24%	11%	0%	14%	9%	21%	14%	13%
Pumping	5%	4%	6%	2%	8%	0%	0%	21%	0%	3%	21%	14%	2%
Other	8%	13%	8%	7%	4%	10%	5%	7%	5%	9%	13%	8%	8%
Don't know	1%	0%	2%	0%	0%	2%	0%	0%	0%	1%	0%	0%	1%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

Exhibit E.101
Second Largest Energy Use

	DEMAND RESPONSE PARTICIPANT END OF SUMMER SURVEY												
EC9B. Which of the following is the second largest end use in terms of electricity consumption for this facility?	Total	Small	Medium	Large	Extra Large	Commercial	Industrial	Institutional	PG&E	SCE	SDG&E	CPP Participant	DBP Participant
Lighting	42%	35%	48%	37%	42%	51%	31%	54%	28%	50%	42%	38%	44%
HVAC	18%	4%	23%	22%	17%	20%	15%	29%	21%	16%	21%	16%	19%
Continous processing	12%	9%	10%	17%	8%	7%	18%	4%	21%	9%	4%	14%	11%
Batch processing	12%	22%	8%	10%	13%	5%	21%	4%	16%	10%	8%	14%	11%
Refrigeration	4%	4%	2%	7%	0%	5%	3%	4%	0%	4%	8%	3%	4%
Pumping	1%	0%	2%	0%	0%	2%	0%	0%	0%	1%	0%	0%	1%
Ovens	1%	0%	4%	0%	0%	0%	2%	4%	0%	1%	4%	3%	1%
Conveyers	1%	4%	0%	0%	4%	2%	2%	0%	2%	1%	0%	0%	2%
Other	7%	17%	2%	7%	8%	7%	7%	4%	12%	4%	8%	11%	6%
Don't know	2%	4%	0%	0%	8%	0%	2%	0%	0%	3%	4%	3%	2%
N	137	23	48	41	24	41	61	28	43	70	24	37	104

* N is the number of respondents.

APPENDIX F
BASELINE ANALYSIS TABLES

APPENDIX F
BASELINE ANALYSIS TABLES

This appendix accompanies Chapter 6, the Baseline Assessment Chapter. It includes the following sections:

1. **F.1:** All baseline days by Utility (PG&E, SCE and SDG&E). It is important to note that for SDG&E the sample population is very small (N=39). The tables include:
    - Metric 1 - Bias Calculations,
    - Metric 2 - Error Magnitude, and
    - Metric 3 - Regression Analysis.
2. **F.2:** Cumulative distribution of the errors for populations of various sizes. The tables include:
    - Small Customers (200-500 kW)
    - Medium Customers (500 –1,000 kW)
    - Large Customers (1,000 – 2,000 kW)
    - Extra Large Customers (+2,000 kW)

APPENDIX F.1

PG&E Bias and Error Magnitude for All Event Days

PG&E Baseline Details			Bias	Error Magnitude	
Program	**Baseline Type**	**Adjustment**	**Median RHE**	**Median Thiel's U**	**95th % Thiel's U**
CPP	3-Day	None	0.013	0.091	0.772
	10-Day	None	-0.031	0.096	0.473
		Prior-Day	-0.007	0.097	0.486
	Prior Day	None	-0.007	0.109	0.778
DBP	3-Day	None	0.013	0.082	0.478
		Same-Day	0.012	0.083	0.473
	10-Day	None	-0.03	0.097	0.501
		Prior-Day	-0.008	0.098	0.579
		Same-Day	0.001	0.06	0.452
	Prior Day	None	-0.007	0.098	0.51

SCE Bias and Error Magnitude for All Event Days

SCE Baseline Details			Bias	Error Magnitude	
Program	**Baseline Type**	**Adjustment**	**Median RHE**	**Median Thiel's U**	**95th % Thiel's U**
CPP	3-Day	None	0.019	0.104	0.787
	10-Day	None	-0.014	0.074	0.525
		Prior-Day	-0.001	0.076	0.504
	Prior Day	None	-0.002	0.09	0.792
DBP	3-Day	None	0.021	0.086	0.615
		Same-Day	0.019	0.083	0.615
	10-Day	None	-0.014	0.077	0.486
		Prior-Day	-0.002	0.078	0.501
		Same-Day	0.002	0.056	0.445
	Prior Day	None	-0.002	0.077	0.625

SDG&E Bias and Error Magnitude for All Event Days

SDG&E Baseline Details			Bias	Error Magnitude	
Program	Baseline Type	Adjustment	Median RHE	Median Thiel's U	95th % Thiel's U
CPP	3-Day	None	0.057	0.136	0.457
	10-Day	None	-0.002	0.099	0.268
		Prior-Day	0.009	0.09	0.281
	Prior Day	None	0.012	0.077	0.415
DBP	3-Day	None	0.056	0.128	0.425
		Same-Day	0.054	0.13	0.425
	10-Day	None	0.001	0.095	0.325
		Prior-Day	0.01	0.085	0.34
		Same-Day	0.029	0.081	0.337
	Prior Day	None	0.012	0.071	0.386

PG&E Regression Coefficients for All Event Days

Day Type	Program	Baseline Type	Adjustment	Coef.	t-value	R-Square
Overall	CPP	3-Day	None	0.97	887	0.86
		10-Day	None	1.01	1446	0.94
			Prior-Day	0.98	1422	0.94
		Prior Day	None	0.96	679	0.79
	DBP	3-Day	None	0.97	1560	0.95
		10-Day	None	1.01	1437	0.94
			Prior-Day	0.98	1254	0.93
			Same-Day	1.00	3010	0.99
		Prior Day	None	0.92	546	0.71

SCE Regression Coefficients for All Event Days

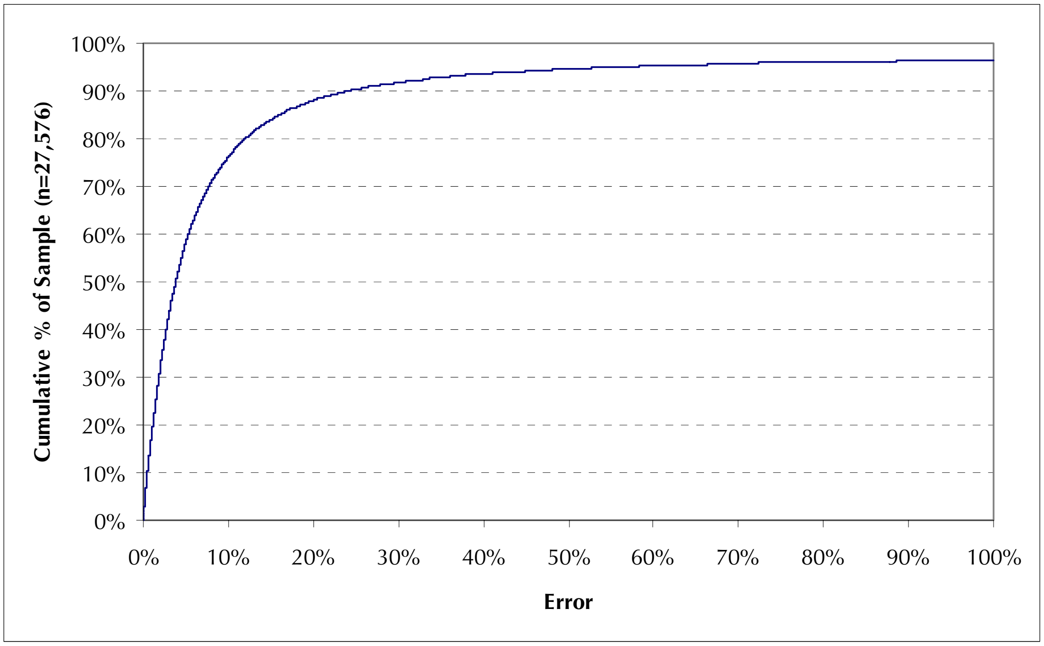
Day Type	Program	Baseline Type	Adjustment	Coef.	t-value	R-Square
Overall	CPP	3-Day	None	0.95	719	0.81
		10-Day	None	1.00	1335	0.94
			Prior-Day	0.98	1169	0.92
		Prior Day	None	0.94	788	0.83
	DBP	3-Day	None	0.87	628	0.76
		10-Day	None	0.97	848	0.85
			Prior-Day	0.91	810	0.84
			Same-Day	0.99	1842	0.97
		Prior Day	None	0.76	348	0.49

SDG&E Regression Coefficients for All Event Days

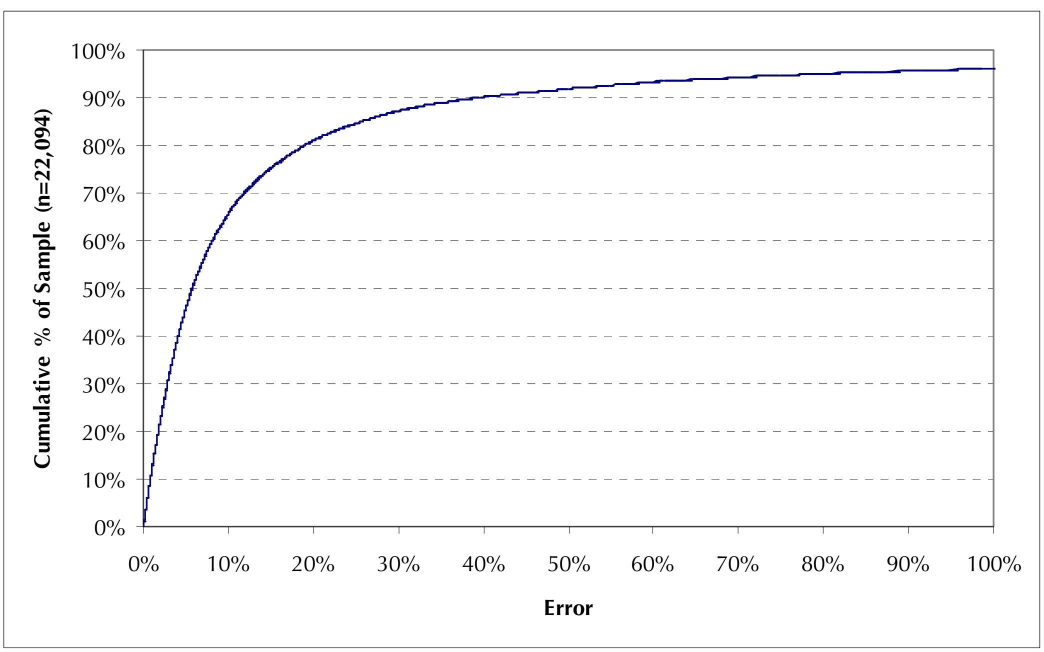
Day Type	Program	Baseline Type	Adjustment	Coef.	t-value	R-Square
Overall	CPP	3-Day	None	0.86	719	0.81
		10-Day	None	0.95	790	0.83
			Prior-Day	0.95	947	0.88
		Prior Day	None	0.97	369	0.52
	DBP	3-Day	None	0.91	310	0.44
		10-Day	None	0.98	352	0.50
			Prior-Day	0.95	381	0.54
			Same-Day	0.96	657	0.78
		Prior Day	None	0.67	165	0.18

APPENDIX F.2

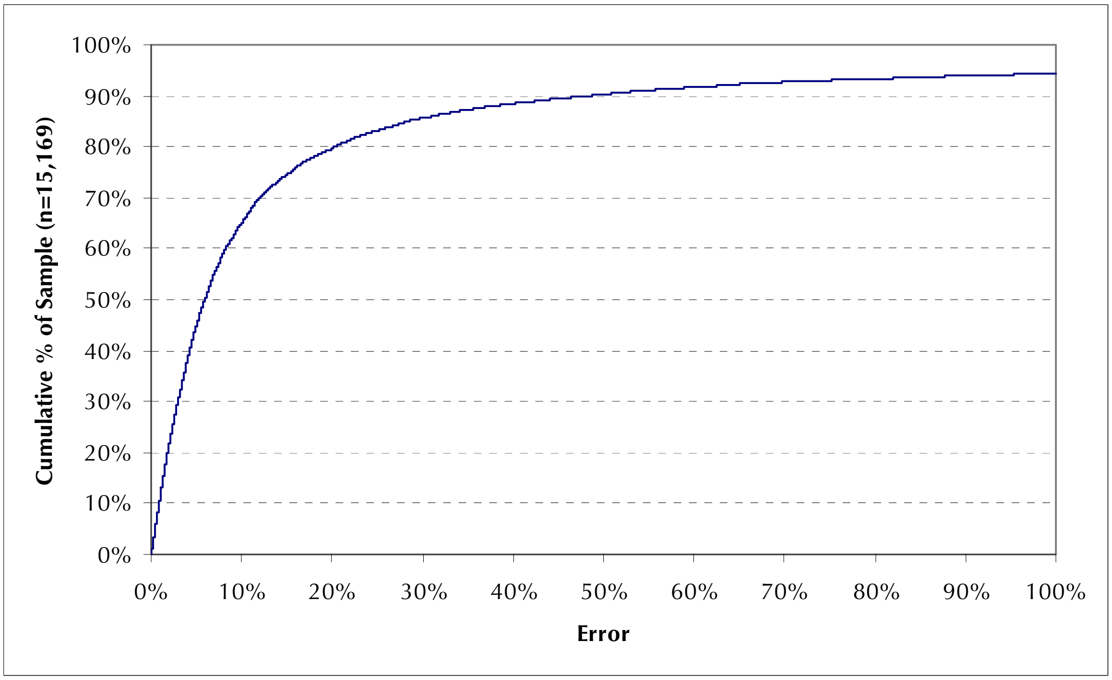
Cumulative Distribution of Error for DBP 3-Day Baseline for Small Sized Customers (200-500kW)



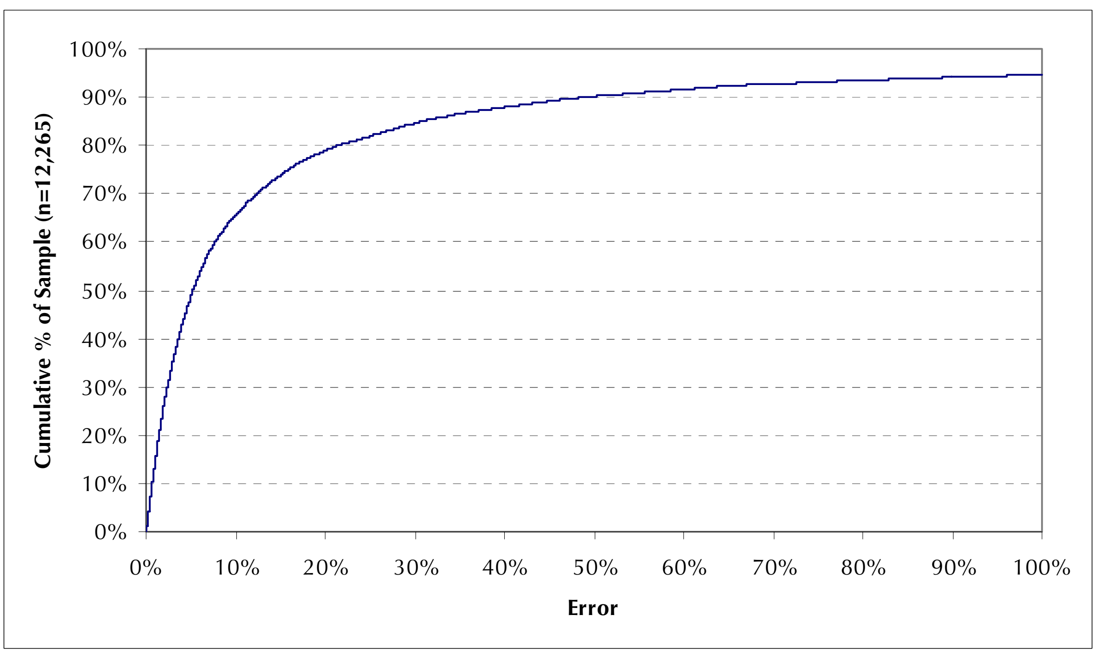
Cumulative Distribution of Error for DBP 3-Day Baseline for Medium Sized Customers (500-1000kW)



Cumulative Distribution of Error for DBP 3-Day Baseline for Large Sized Customers (1000-2000kW)



Cumulative Distribution of Error for DBP 3-Day Baseline for Extra Large Sized Customers (2000+kW)



APPENDIX G
IMPACT ANALYSIS TABLES

APPENDIX G
SUPPORTING IMPACT ANALYSIS TABLES

This appendix accompanies Chapter 7, the Impact Analysis Chapter. It includes the following sections:

1. **G.1:** Counting Estimated Load Differences: Distributions of individual hourly impacts based on the 3-Day and 10-Day adjusted baselines for all DBP events for each of the three utilities.

2. **G.2:** Impact estimates resulting from the three alternatives considered for counting impacts for DBP - All Differences, All Positive Differences and All Differences (both positive and negative) that are greater than a 10% tolerance (based on a percent of their annual maximum load). This is an area where additional research would be beneficial but was not included as part of this analysis due to the degree of uncertainty that existed around the impact estimates already due to the number of program participants and the limited non-test events.

APPENDIX G.1
COUNTING ESTIMATED LOAD DIFFERENCES

Distributions of Individual Hourly Impacts based on the 3-Day and 10-Day Adjusted Baselines for all DBP Events by Utility (Alternative 2 for Bidders used to Calculate DBP Program Impacts)

			Average Hourly Reduction (MW's) - 10-Day Adjusted Baseline					
			Bidders			All Participants		
Utility	Event	Event Date	Alternative 1: All Differences	Alternative 2: All Positive Differences	Alternative 3: Differences > 10% Tolerance	Alternative 1: All Differences	Alternative 2: All Positive Differences	Alternative 3: Differences > 10% Tolerance
SDG&E	DBP #1	05/03/04	0.5	0.5	0.4	0.6	0.9	0.5
	DBP #2	06/30/04	1.0	1.0	1.0	0.6	2.5	1.1
	DBP #3	09/07/04	0.9	1.0	0.8	0.8	1.6	0.9
SCE	DBP #1	06/09/04	11.3	11.7	11.3	6.8	28.9	6.1
	DBP #2	09/23/04	3.3	5.6	3.3	2.6	15.6	2.8
PG&E	DBP #1	07/26/04	12.8	15.1	11.9	12.8	15.1	11.9
		All	29.7	34.9	28.7	24.2	64.6	23.3

Comparison of Alternatives for DBP Bidder and All Participant Populations

Differences	Bidders	All Participants
Alt 1 vs Alt 2	-15%	-63%
Alt 3 vs Alt 2	-18%	-64%

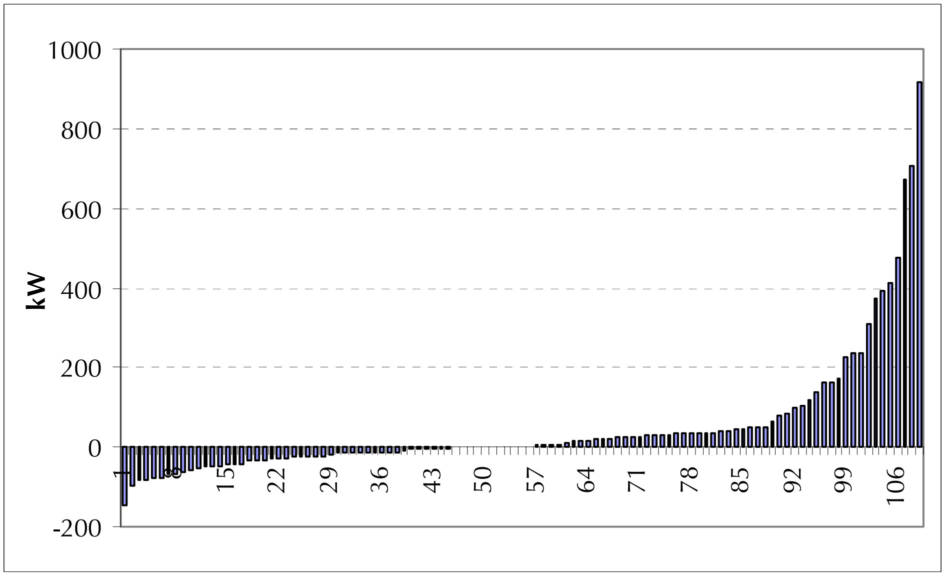
Comparison of Bidders versus All Participants across all Counting Alternatives

Differences	Alternative 1	Alternative 2	Alternative 3
Bidders vs All	-19%	85%	-19%

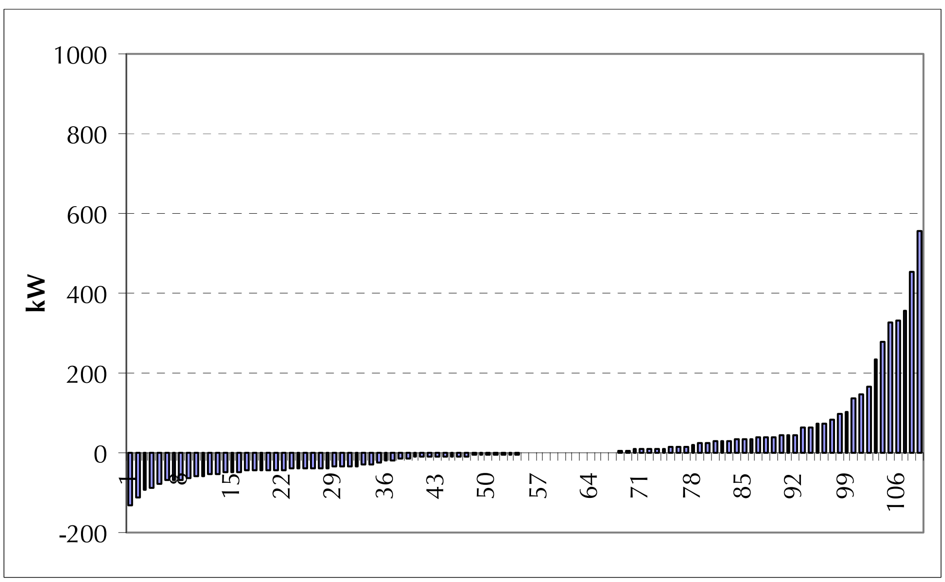
APPENDIX G.2
COMPARISON OF THE AVERAGE ESTIMATED PROGRAM IMPACTS RESULTING FROM THE 3-DAY AND 10-DAY ADJUSTED BASELINES BY CUSTOMER FOR ALL EVENTS

PG&E CPP
***PG&E CPP* Event #1 – August 27,2004**

3-Day Baseline

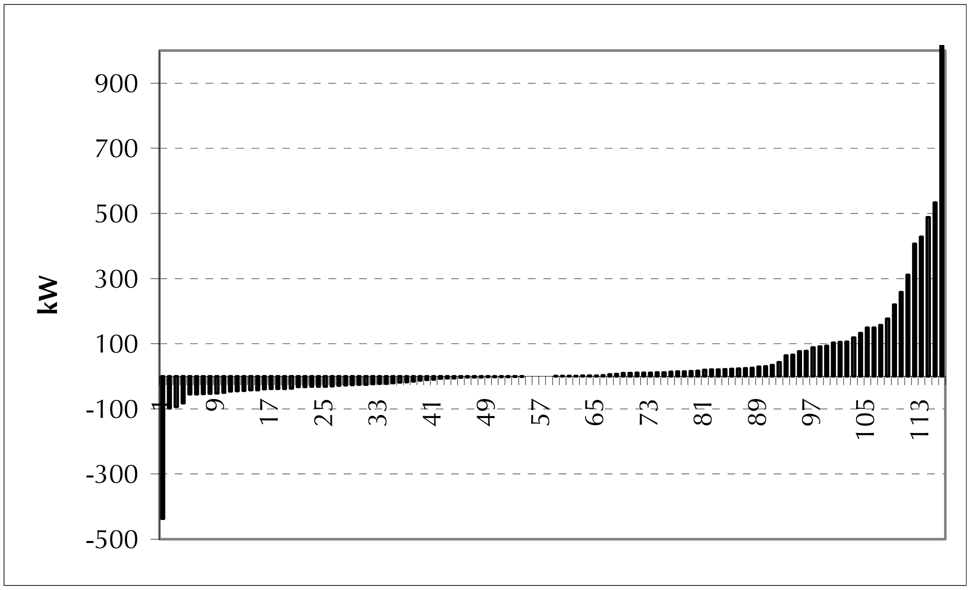


10-Day Adjusted Baseline

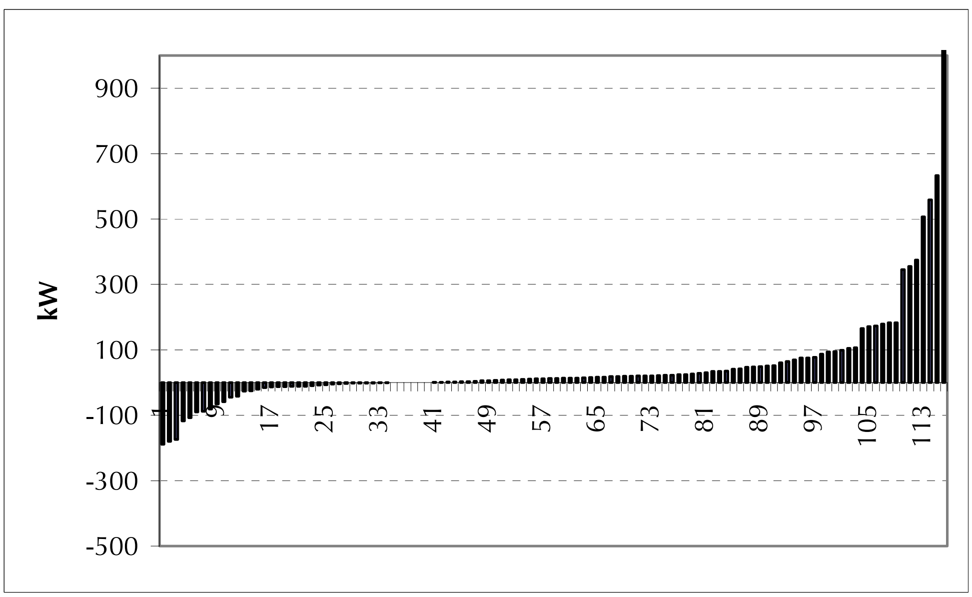


PG&E CPP Event #2 – September 8, 2004

3-Day Baseline

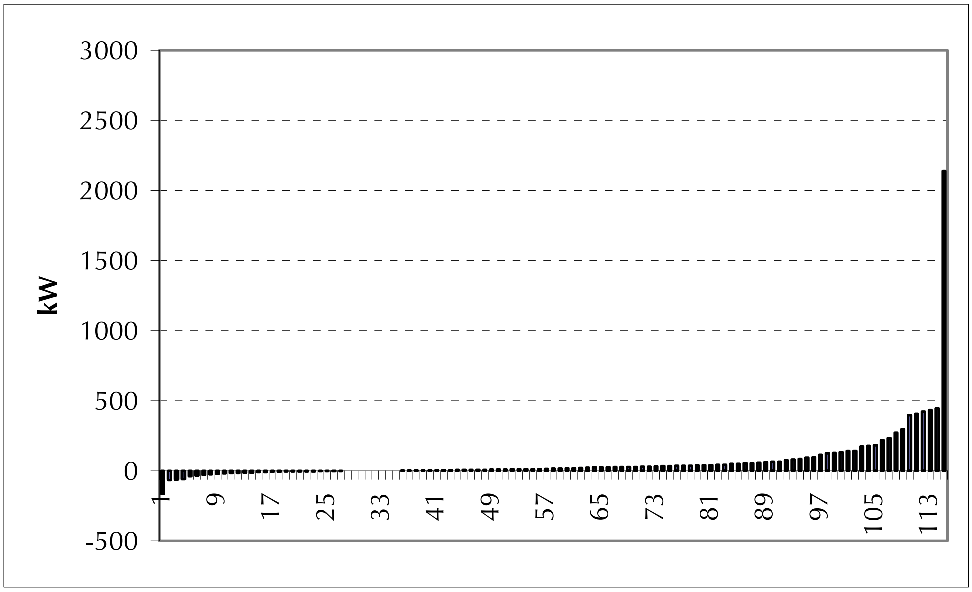


10-Day Adjusted Baseline

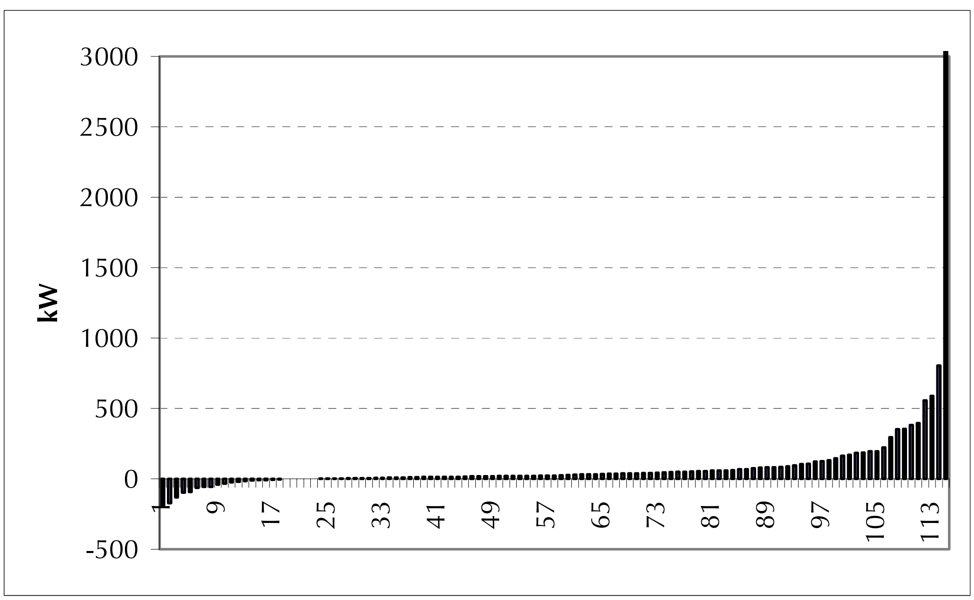


PG&E CPP Event #3 – September 9, 2004

3-Day Baseline

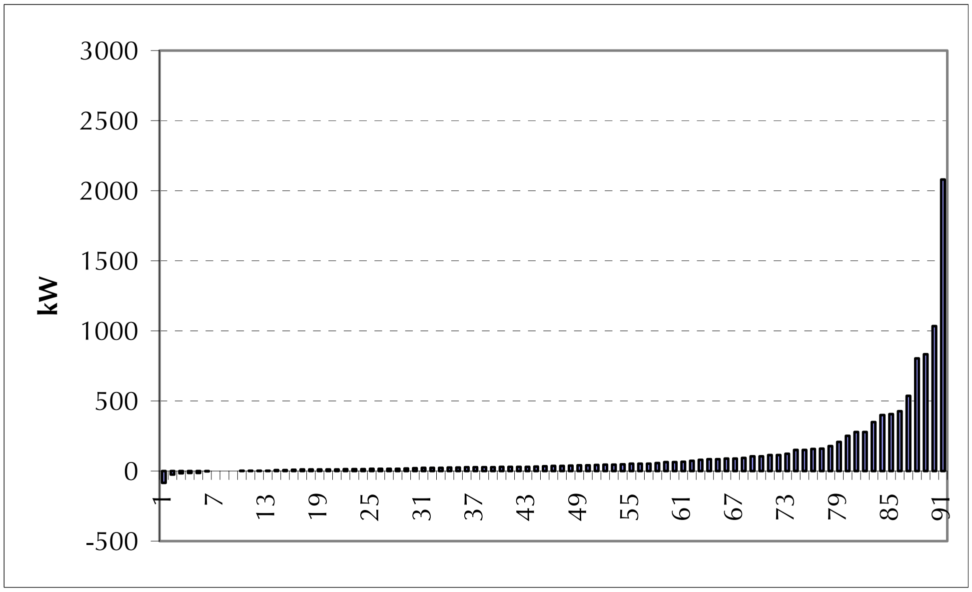


10-Day Adjusted Baseline

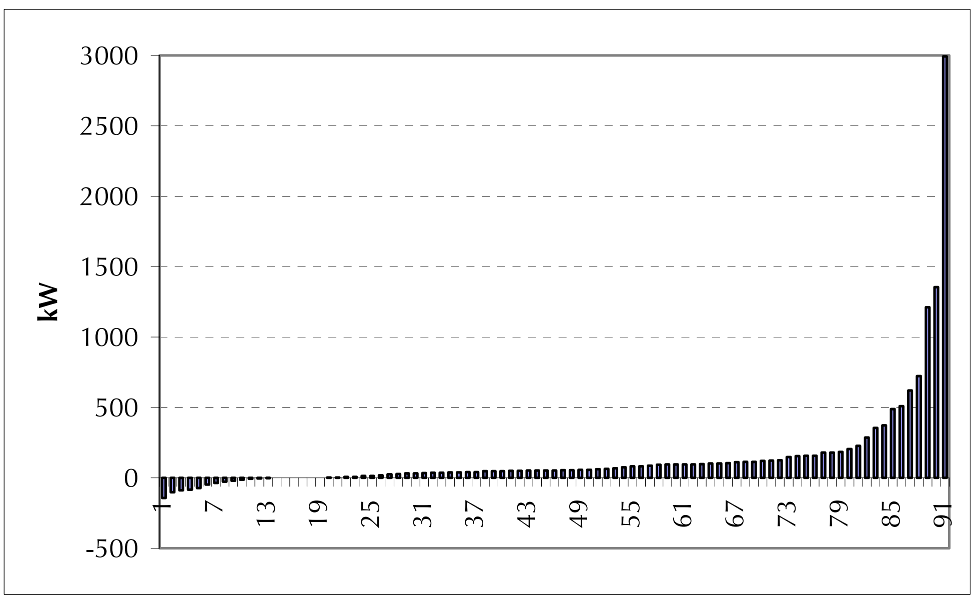


PG&E CPP Event #4 – September 10, 2004

3-Day Baseline

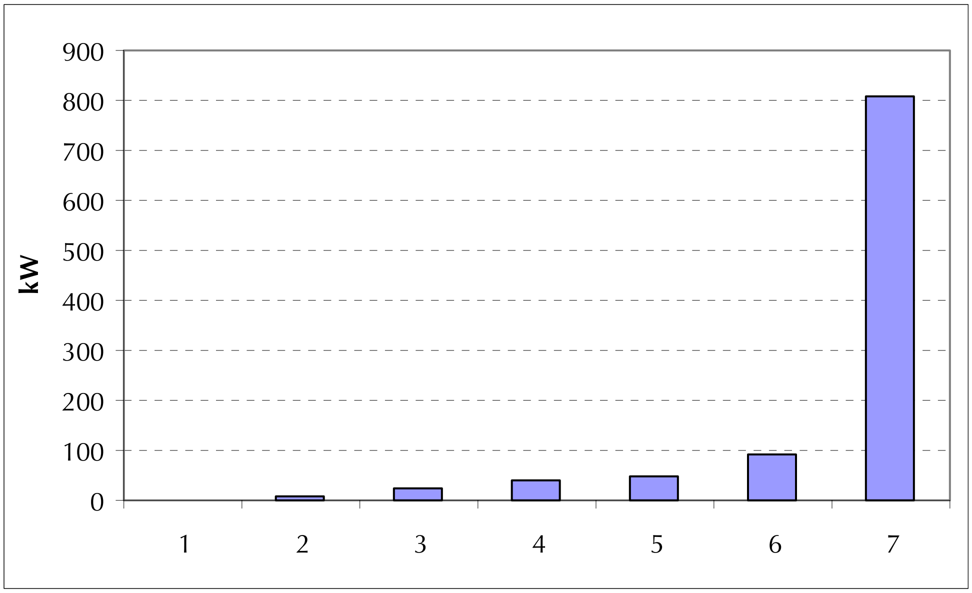


10-Day Adjusted Baseline

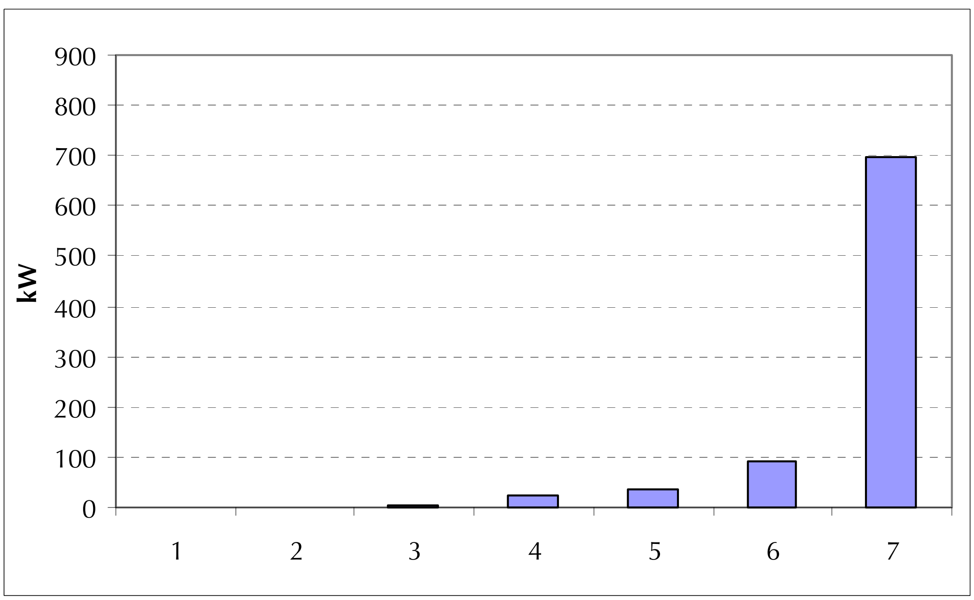


SCE CPP – SCE had 12 events, however only 8 customers (7 with interval data) participated in these events and the estimated program impact for each of these events is very similar and thus only 1 has been included.

3-Day Baseline



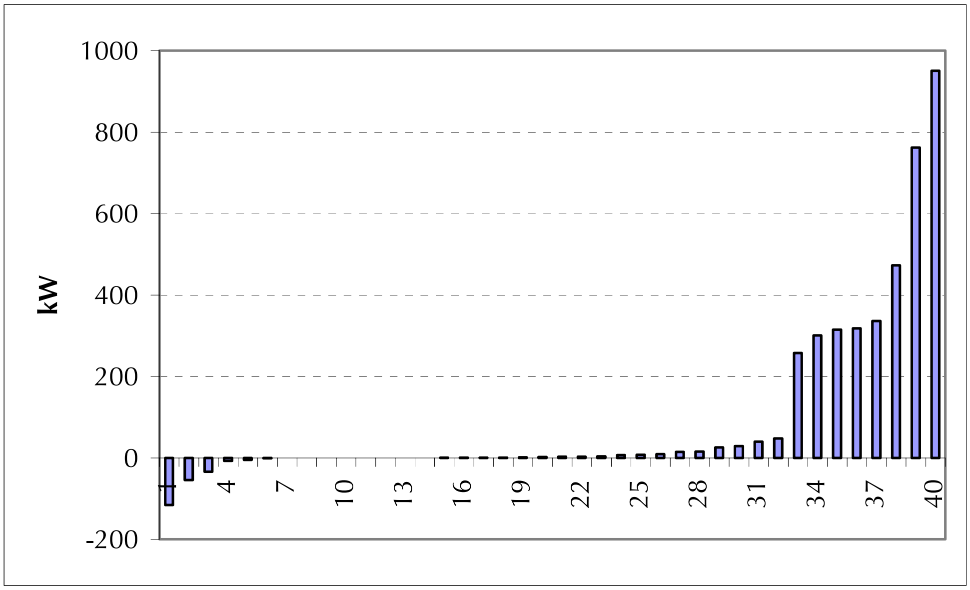
10-Day Adjusted Baseline



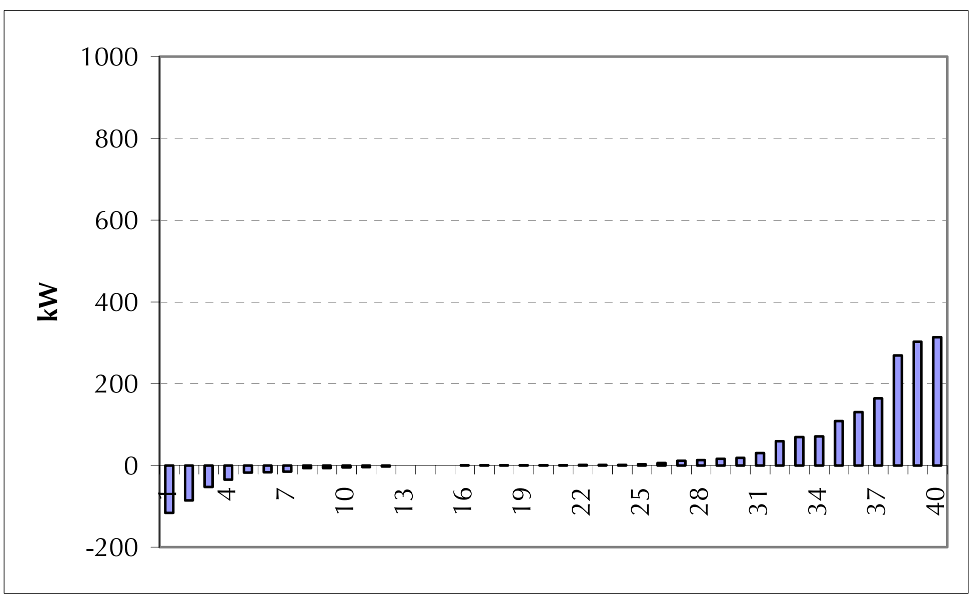
SDG&E CPP

SDG&E CPP Event #1 – July 13, 2004

3-Day Baseline

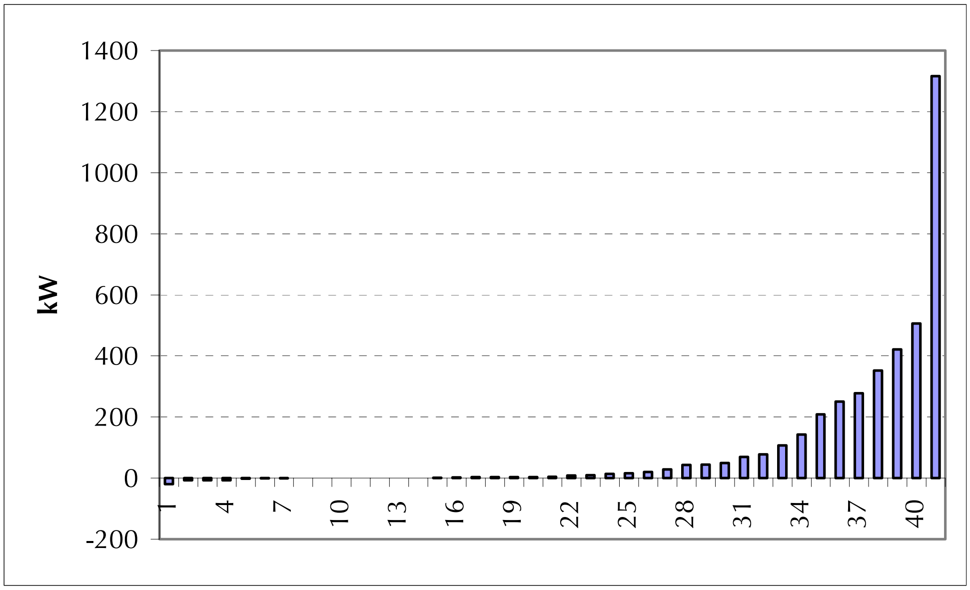


10-Day Adjusted Baseline

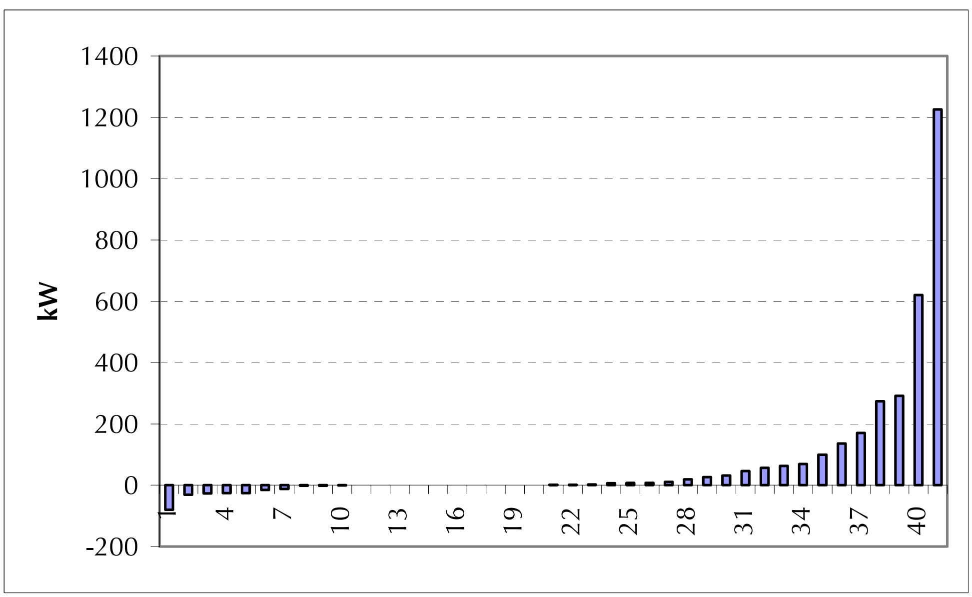


SDG&E CPP Event #2 – July 22, 2004

3-Day Baseline

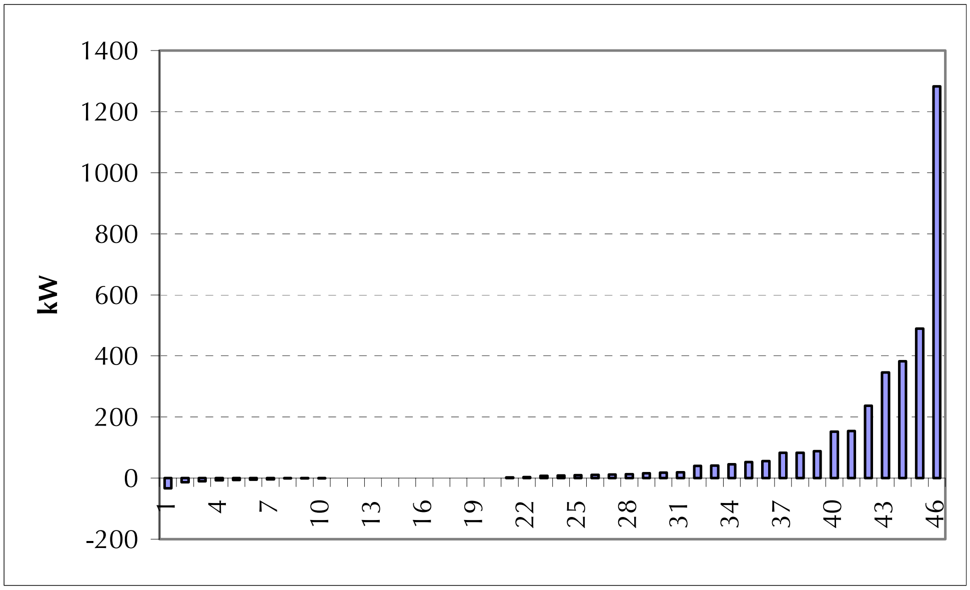


10-Day Adjusted Baseline

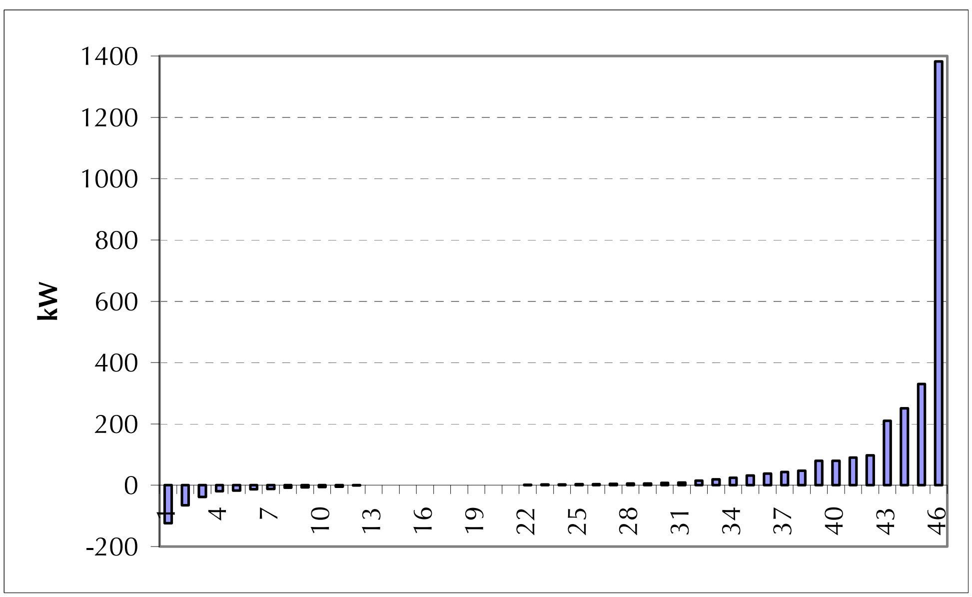


SDG&E CPP Event #3 – August 11, 2004

3-Day Baseline

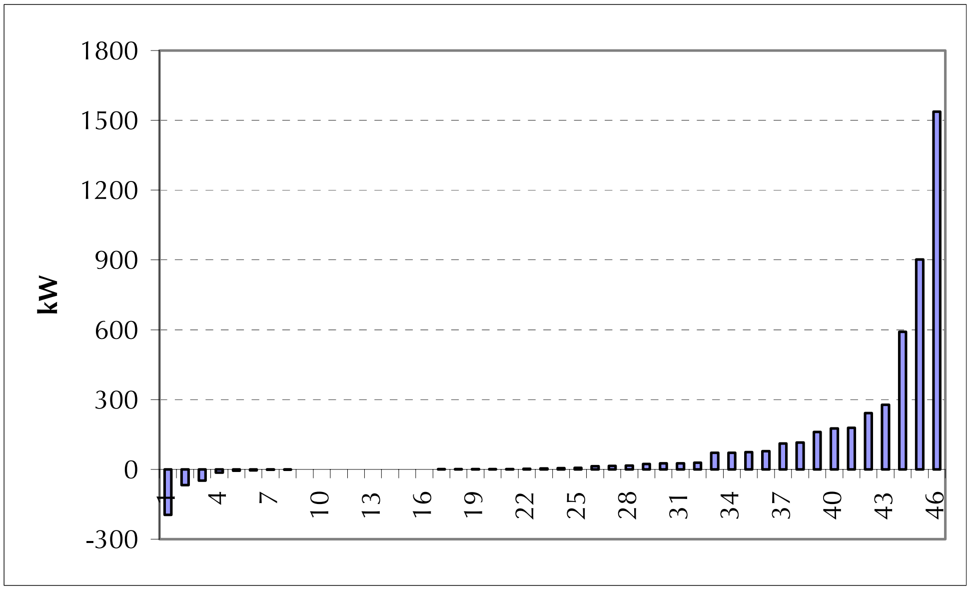


10-Day Adjusted Baseline

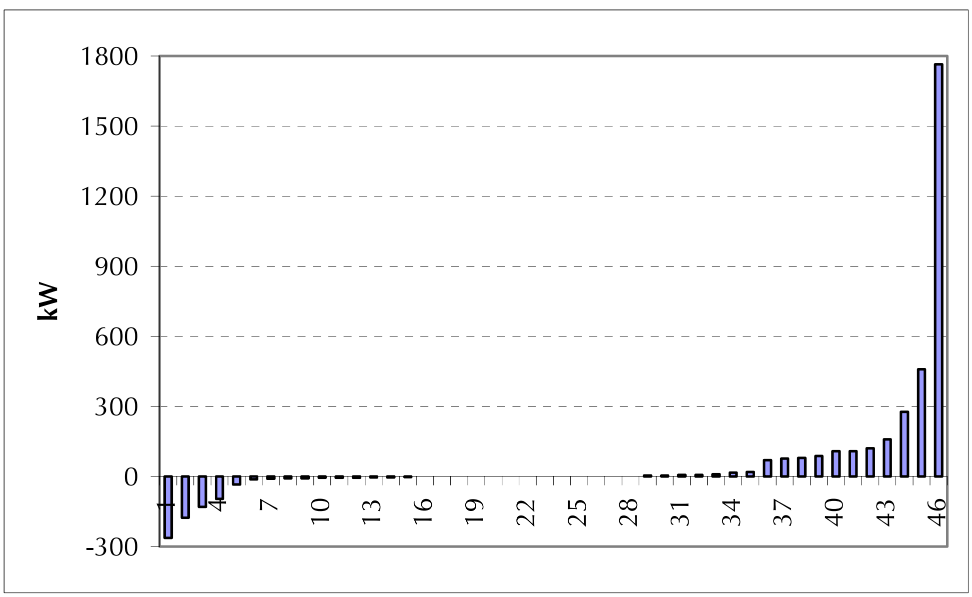


SDG&E CPP Event #4 – September 1, 2004

3-Day Baseline

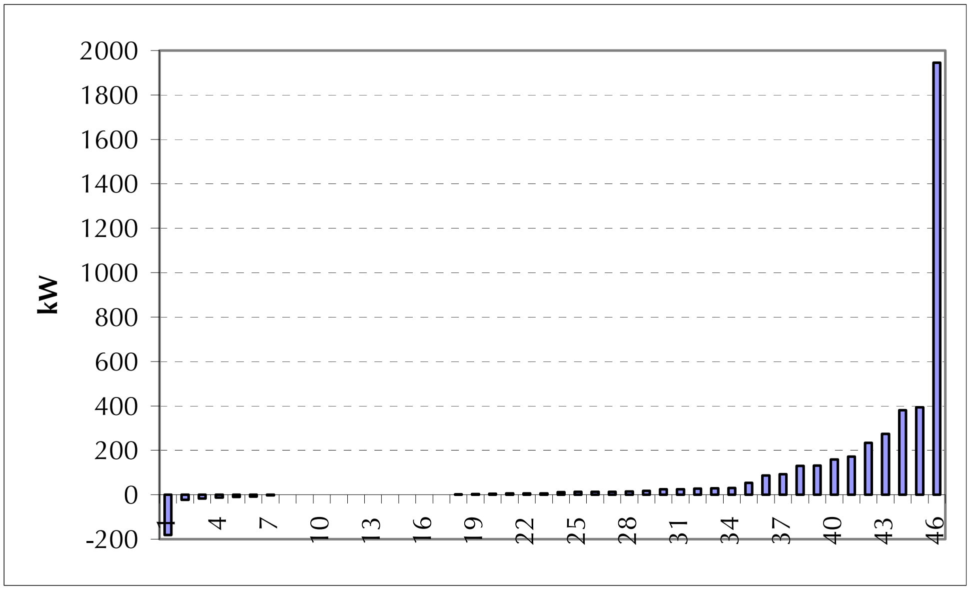


10-Day Adjusted Baseline

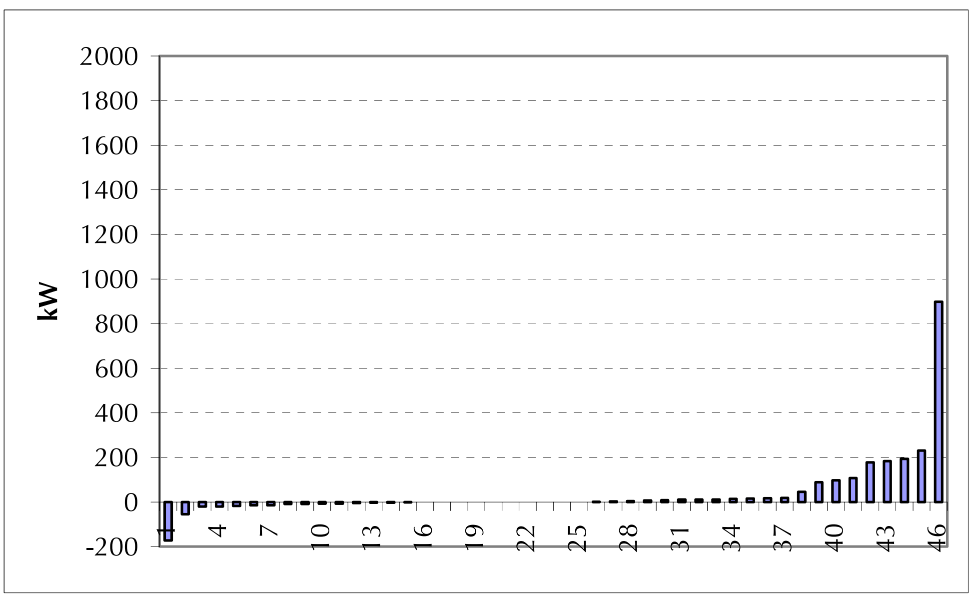


SDG&E CPP Event #5 – September 8, 2004

3-Day Baseline

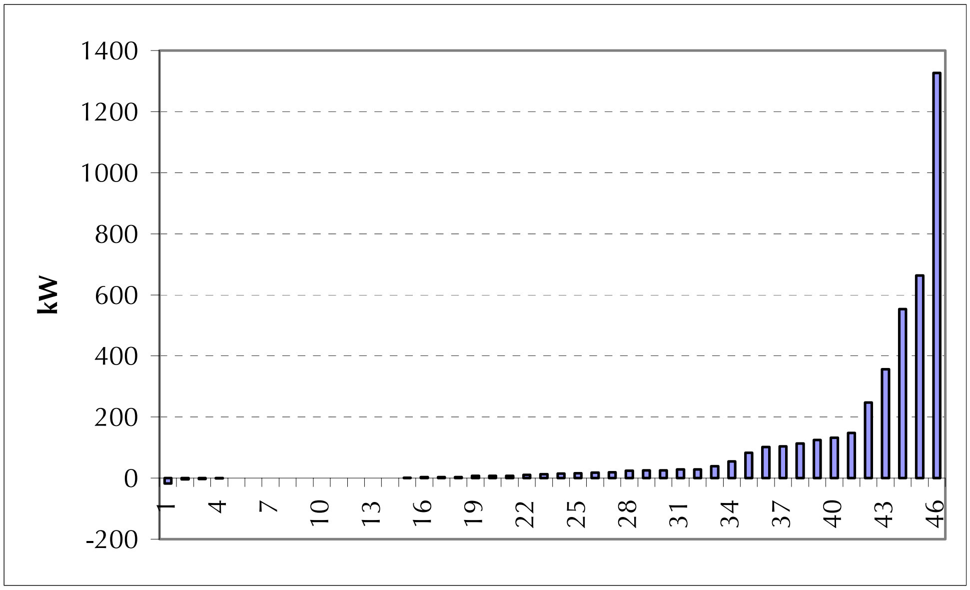


10-Day Adjusted Baseline

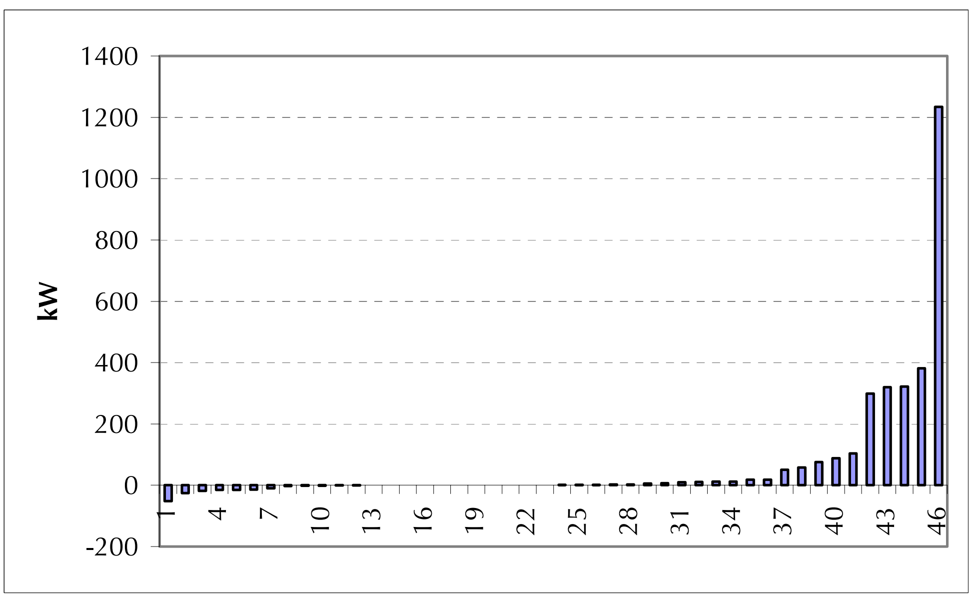


SDG&E CPP Event #6 – September 23, 2004

3-Day Baseline



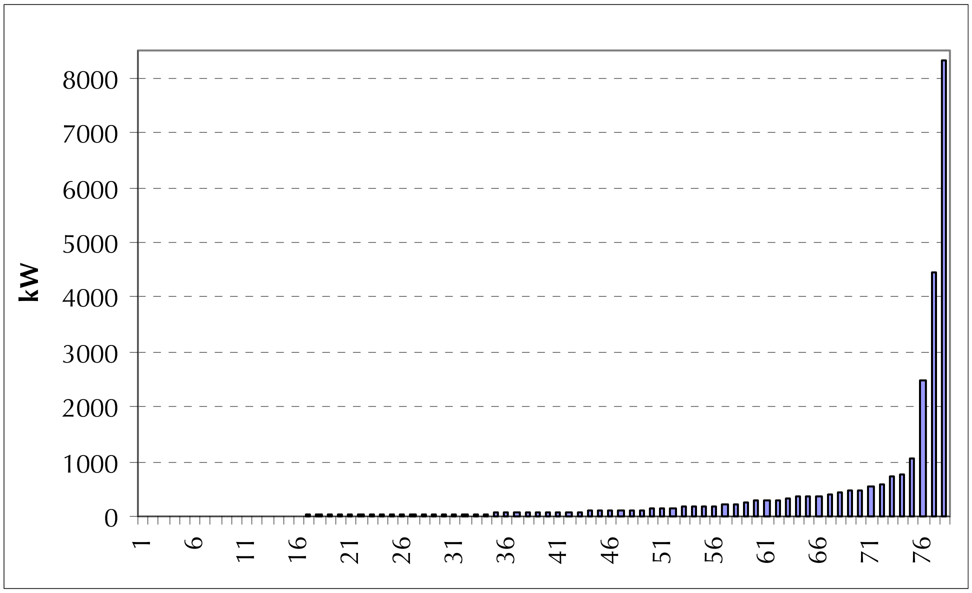
10-Day Adjusted Baseline



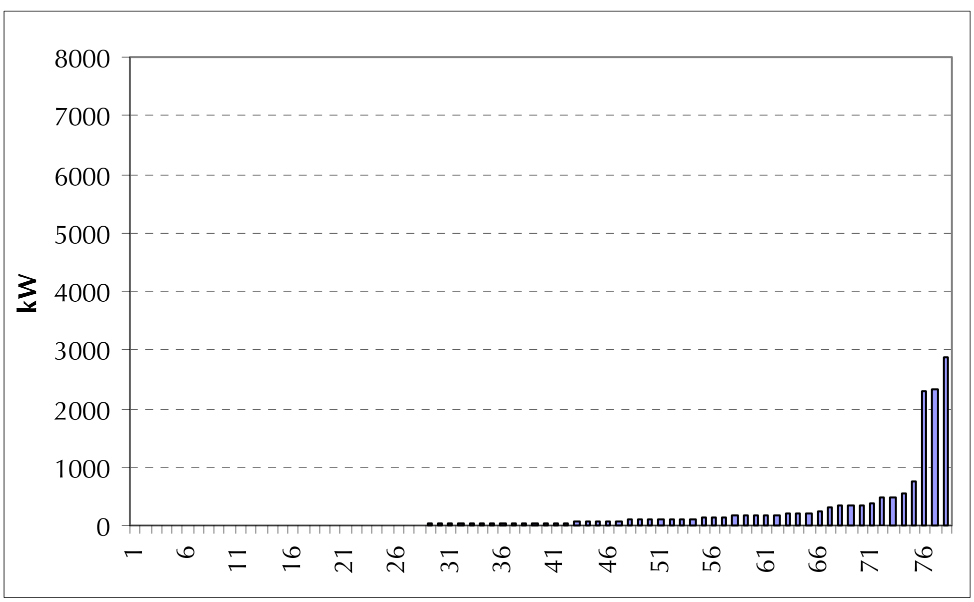
PG&E DBP –

PG&E DBP Event #1 - July 26, 2004

3-Day Baseline



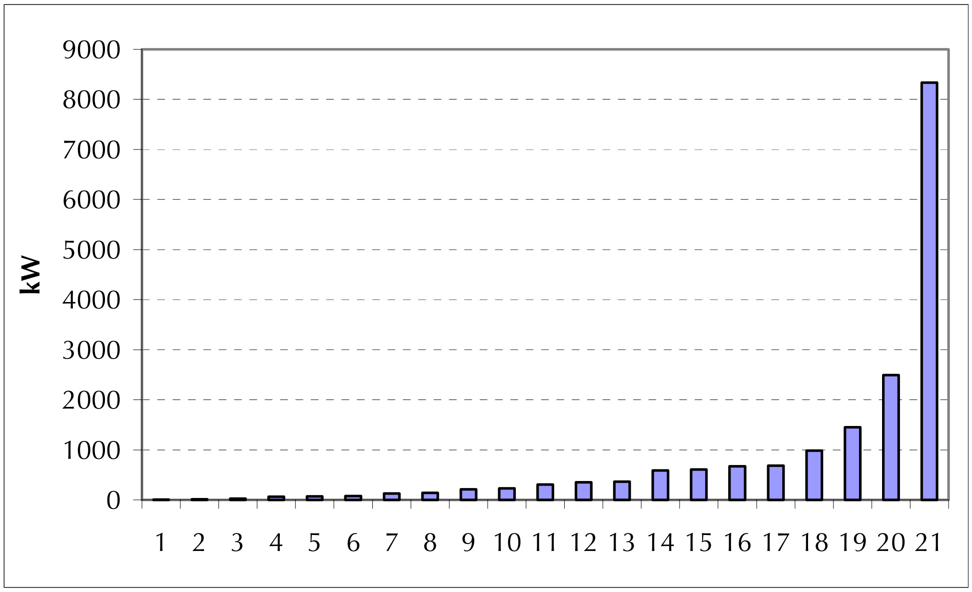
10-Day Adjusted Baseline



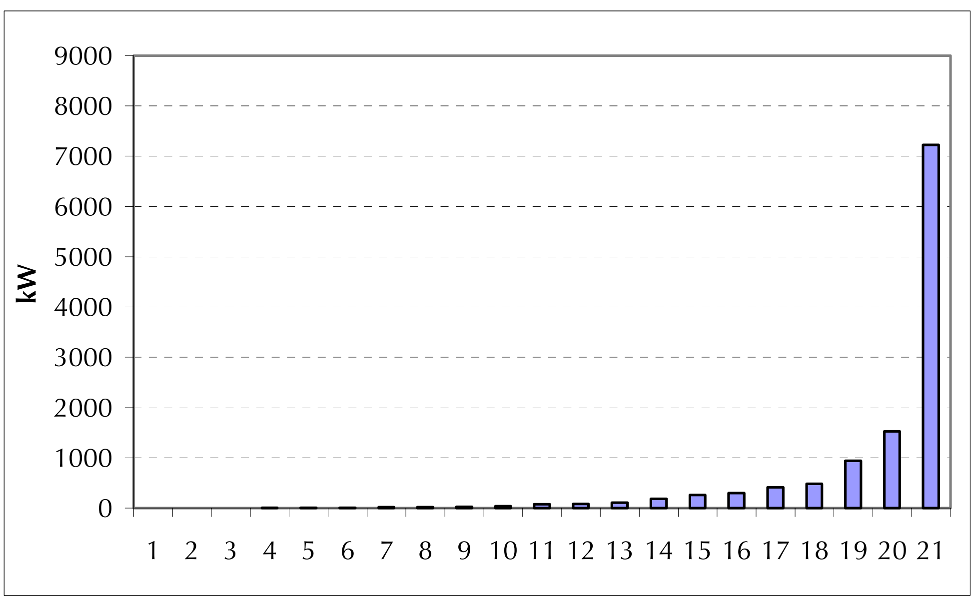
SCE DBP

SCE DBP Event #2 - June 9, 2004

3-Day Baseline

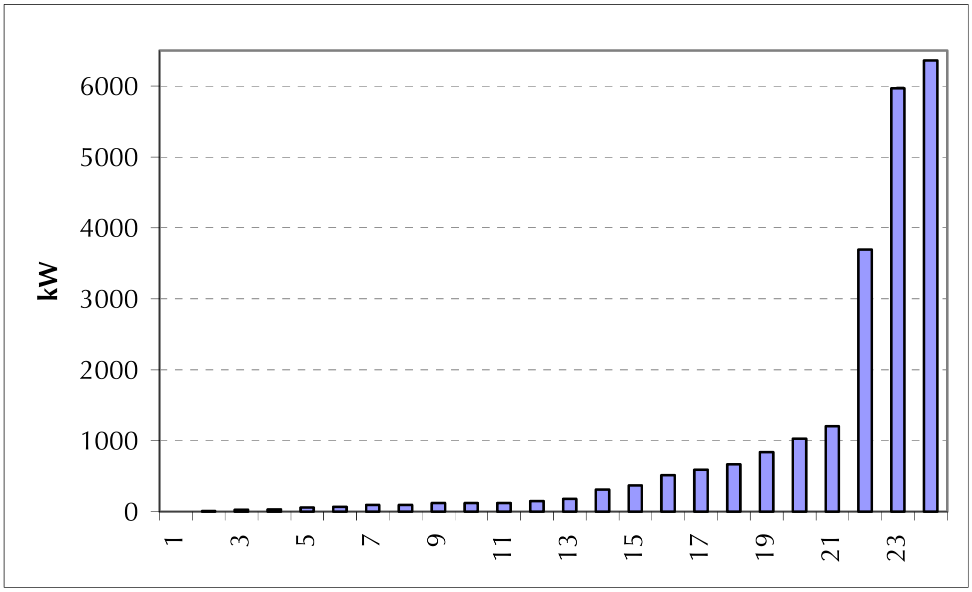


10-Day Adjusted Baseline

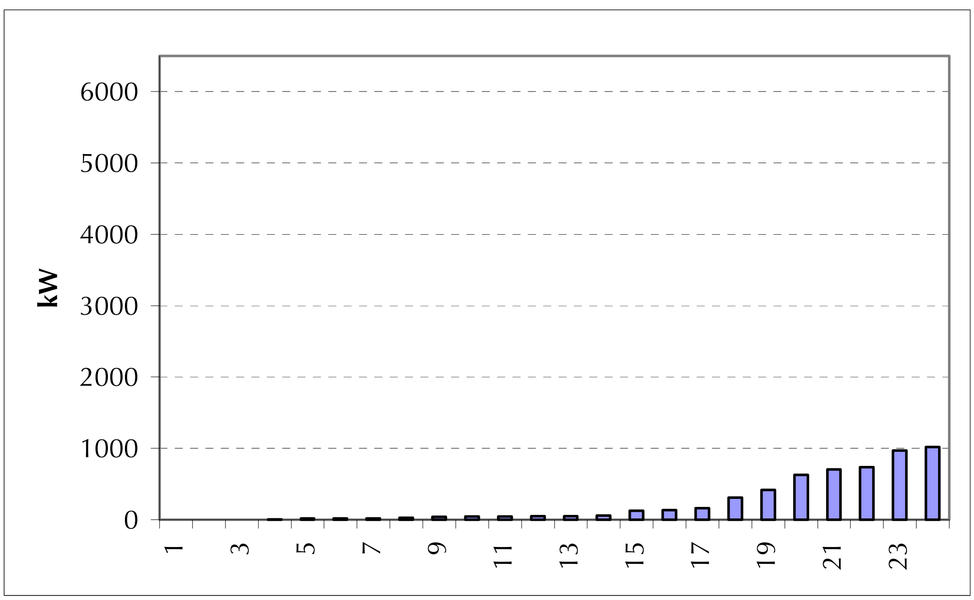


SCE DBP Event #3 - September 23, 2004

3-Day Baseline



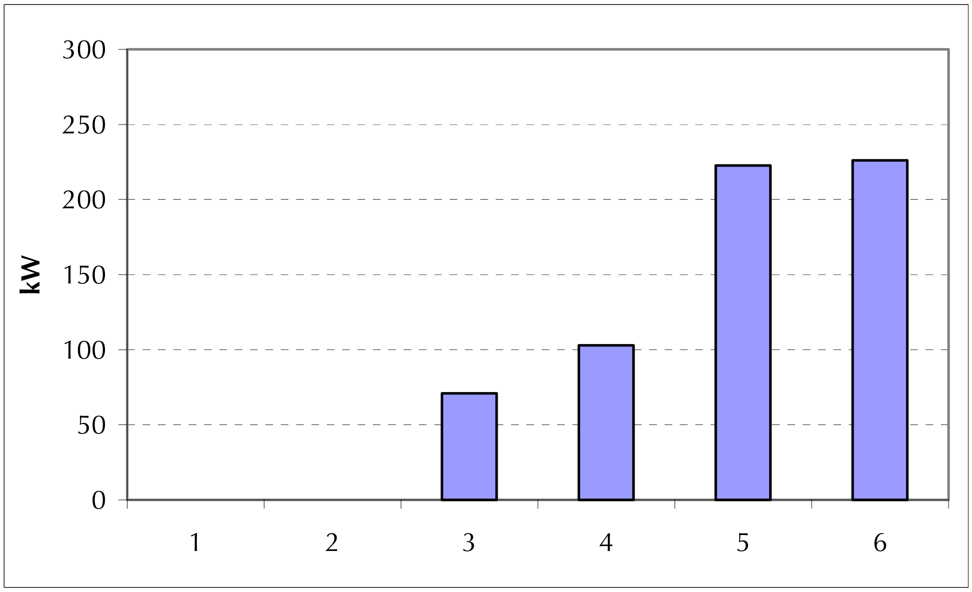
10-Day Adjusted Baseline



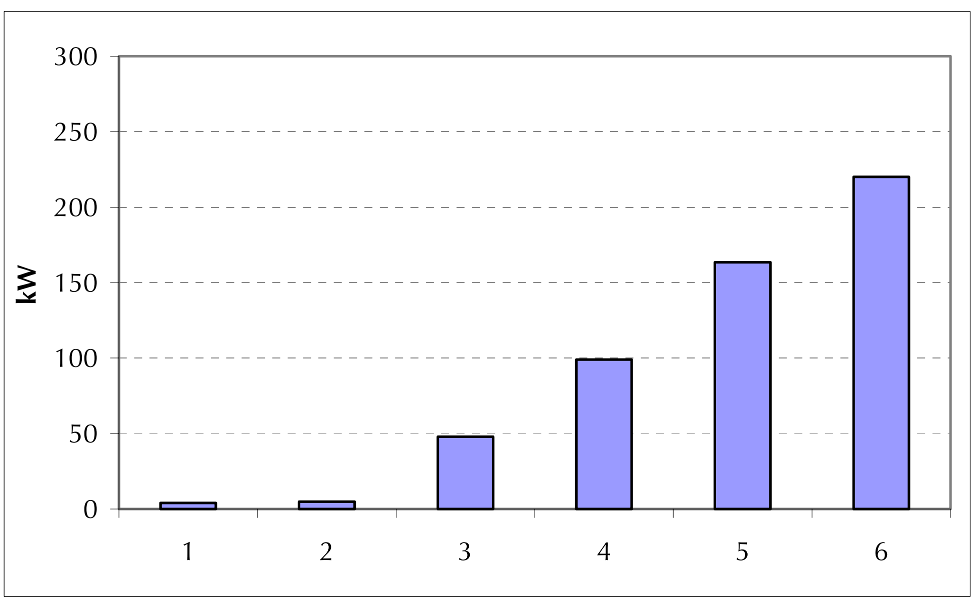
SDG&E DBP

SDG&E DBP Event #1 - May 3, 2004

3-Day Baseline

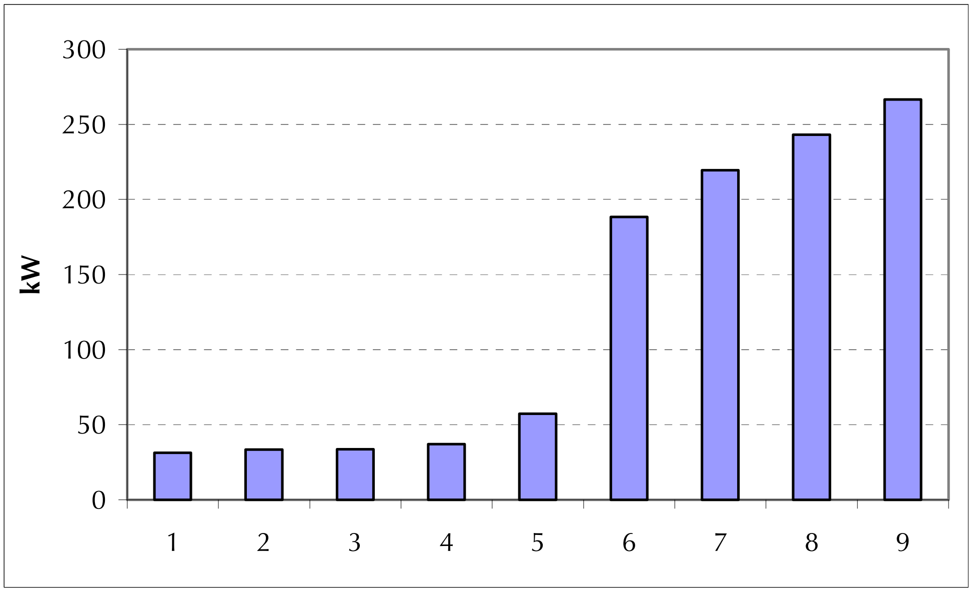


10-Day Adjusted Baseline

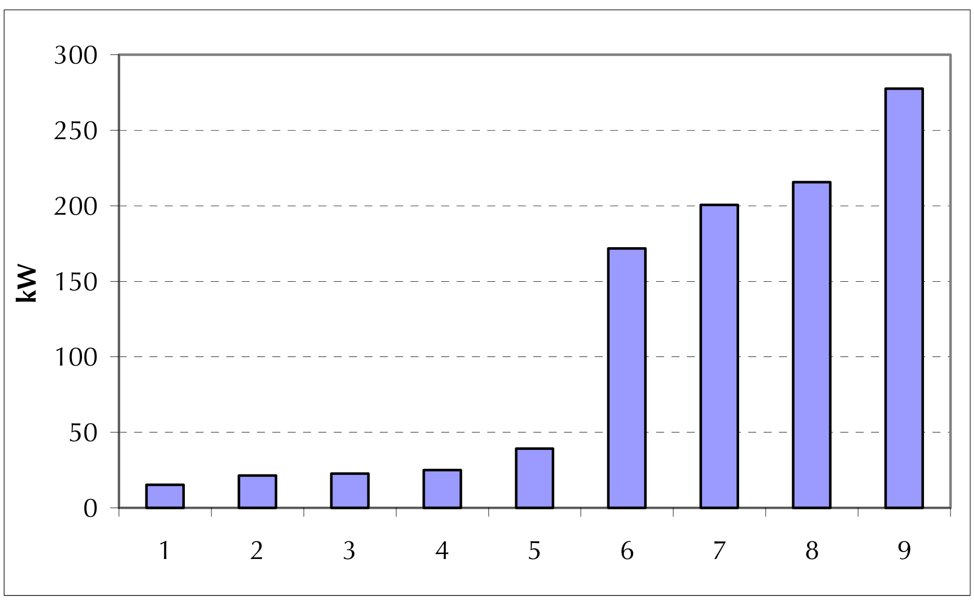


SDG&E DBP Event #2 - June 30, 2004

3-Day Baseline

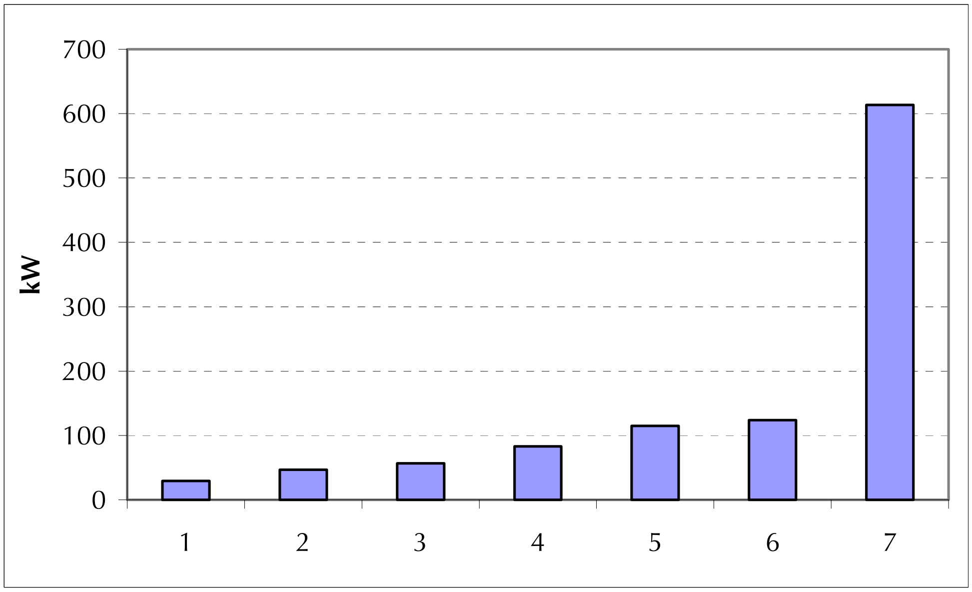


10-Day Adjusted Baseline

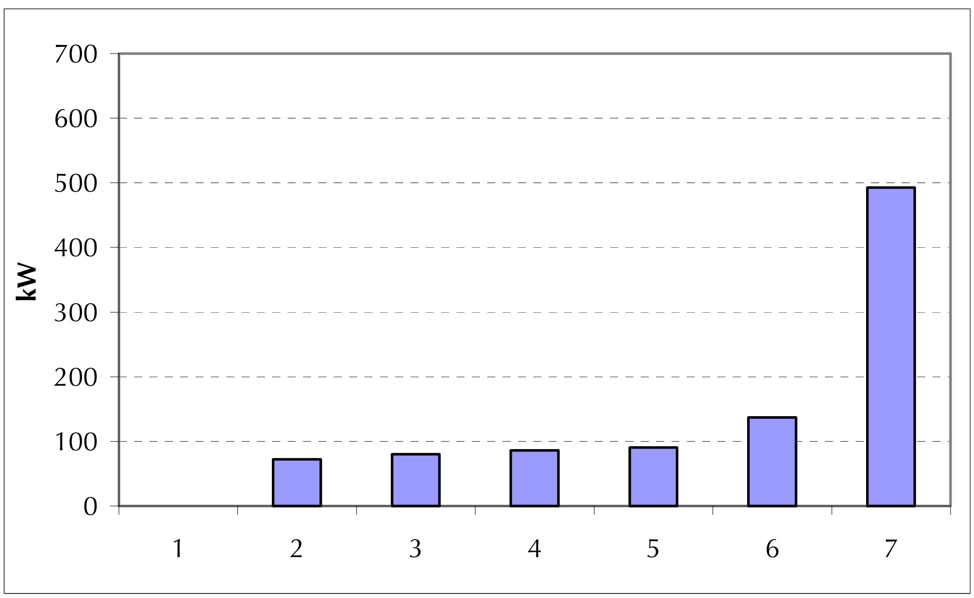


SDG&E DBP Event #3 – September 7, 2004

3-Day Baseline



10-Day Adjusted Baseline



APPENDIX H
PROGRAM FEATURES MATRIX / INTERRUPTIBLE EVENT HISTORY

APPENDIX H.1
PROGRAM FEATURES MATRIX

This appendix contains a compilation of 29 features reflected in various forms in the reliability-triggered interruptible programs included in this evaluation. The features for which information was compiled include the following:

1. Eligibility: Customer Type
2. Eligibility: Minimum Load Reduction Requirements
3. Other Participation Terms
4. Baseline Criteria
5. Participant Event Action Options & Consequences
6. Impact Performance Measure
7. Other Rate Program Eligibility
8. Incentive Options
9. Payment channel
10. Penalty for Non-compliance
11. Penalty Adjudication/Waiver Process
12. Test Event Actions
13. Event Call Criteria
14. Event Period Definition
15. Maximum # of Hours/Event
16. Maximum # of Events/Week or Day
17. Maximum # of Events, Hours/Month
18. Maximum # of Events/Season
19. Maximum # of Events/Year
20. Notification Advance Time Period
21. Notification Method/Channel
22. Response Confirmation Requirement
23. Tracking Hardware/Software
24. Metering Requirements
25. Meter & Account Aggregation Allowed
26. Technical Assistance Options
27. M&V, Survey Participation Requirement

28. Participation Fees/Customer Actions Required
29. Sign-up & Renewal Periods/Cycles

Where features differ among the three utilities for a common program such as the Base Interruptible Program, a separate listing is made by utility. The Traditional Interruptible Programs historically were developed independently by each utility, and so are shown as separate programs under their respective tariff schedule names.

This first version of the feature comparison is still a work in progress, as the data contained in it have not yet been fully verified by program managers.

California Demand Response Evaluation

Emergency-Triggered Interruptible Rate Comparison

Revised 12/13/04

			Traditional IRs			BIP					
			PG&E Sched 19/20	**SCE I-6**	**SDG&E AL TOU CP**	**PG&E**	**SCE**	**SDG&E**	**OBMC/ POBMC**	**RBRP**	**SLRP**
	2004 service accounts (July)		**102**	**515**	**63**	**17**	**61**	**0**	**49**	**65**	**16**
	2004 MW enrolled (July)		**349**	**640**	**25**	**16**	**73**	**0**	**21**	**60**	**4**
1	Eligiblity: Customer Type										
		General	Closed	Closed, except to new customers or eligible customers who are adding new load	Distributed Generation Only	Customers served under A-10, A10-TOU, E-19, or E-20	Customers served under TOU-8, I-6	All TOU metered customers		SDG&E Only	
		kW	> 500 kW	>500 kW	No Minimum	-------------- > 500 kW --------------			No Minimum	No Minimum	100 kW
	Direct Access, Bundled Service		DA and Bundled	DA and Bundled	DA and Bundled	Bundled Only	DA and Bundled	DA and Bundled	DA and Bundled	DA and Bundled	Bundled Only
		Other	Closed even for customer name changes or moves			Except RTP			Single circuit	Generation capability of the greater of 15% of max demand or 100 kW	
2	Eligiblity: Minimum Load Reduction Requirements										
		kW	500 kW	500 kW	No minimum	The greater of 15% of average monthly load or 100 kW, whichever is HIGHER				Higher of 100 kW or 15% of load	100 kW
		% of load				The greater of 15% of average monthly load or 100 kW, whichever is HIGHER			5-15%	Higher of 100 kW or 15% of load	15%
		Other	FSL must be >500 kW less than smallest average peak demand for last 6 summer months						15% load reduction **from circuit**		
3	Other Participation Terms										
		Other		Must be new load	Distributed Generation Capacity				Customer must file OBMC Plan	Site survey - generator data,	Customer pre-schedules dates and times
		Other				Enrollment questionnaire			Single customer takes lead responsibility for compliance		
4	Baseline Critera										
	Firm Service Level		√	√		√	√	√			
	Backup Generator Capacity									√	
		Other							Previous Yr Baseline or 10 previous days' rolling average with affidavit (10% increment)	10 previous days' rolling average	10 previous days' rolling average

	Revised 12/13/04	Traditional IRs			BIP					
		PG&E Sched 19/20	SCE I-6	SDG&E AL TOU CP	PG&E	SCE	SDG&E	OBMC/ POBMC	RBRP	SLRP
	2004 service accounts (July)	**102**	**515**	**63**	**17**	**61**	**0**	**49**	**65**	**16**
5	Participant Event Action Options & Consequences									
	Do Nothing	pay penalty	pay penalty	pay onpeak rate	---------- $6/kWh penalty ----------			$6/kWh penalty	none	removal after 5 events with noncompliance
	Reduce Load Fully	none	none		---------------- none ----------------			Exempt from rolling	$.20/kWh bill credit	$0.10/kWh
	Reduce Load Partially	pay penalty	pay penalty	pay onpeak rate	---------- $6/kWh penalty ----------			$6/kWh penalty	$.20/kWh bill credit	no credit
	Start Backup Generation	√	√	√					√	
	Other								Events count against air quality compliance	Load >15% above baseline after event considered
6	Impact Performance Measure									
	Baseline kW Difference									√
	Backup Generator kW output			√					√	
	Usage minus FSL>/= 0	√	√		√	√	√			
	Other							circuit load		
7	Other Rate Program Eligibility									
	Non-firm				√ - Must first fulfill Sched 19/20 NF pgm req'ts	√ - Must fulfill I-6 hrs first	√ - Must fulfill AL TOU CP hrs 1st	√		√ - must fulfill non-firm hrs 1st
	BIP	√ - Must first fulfill Sched 19/20 NF pgm req'ts	√ - Must fulfill I-6 hrs first	√ - Must fulfill AL TOU CP hrs 1st				√ - only if on dedicated circuit	√	√ - must fulfill non-firm hrs 1st
	CPA DRP	√ - Where DRP load is below FSL	√		√ - add'l load below BIP FSL	√ - add'l load below BIP FSL	√ - add'l load below BIP FSL	√	√	
	CPP								√	
	DBP	√ - But no DBP incentive during NF hrs.		√ - Must fulfill AL TOU CP hrs 1st	√	√	√	√ - no DBP pmts for overlapping events	√	√ - no DBP pmts for overlapping events
	OBMC	√	√	√ - Must fulfill AL TOU CP hrs 1st	√	√	√		√	
	RBRP			√ - Must fulfill AL TOU CP hrs 1st			√	√		√
	SLRP			√ - Must fulfill AL TOU CP hrs 1st				√	√	
	SDG&E HPO									

	Revised 12/13/04	Traditional IRs			BIP					
		PG&E Sched 19/20	SCE I-6	SDG&E AL TOU CP	PG&E	SCE	SDG&E	OBMC/ POBMC	RBRP	SLRP
	2004 service accounts (July)	**102**	**515**	**63**	**17**	**61**	**0**	**49**	**65**	**16**
8	Incentive Options									
	$ Incentive Payment	$7.50 reduction in per kW summer peak demand charge above FSL	Reduced kWh and kW year-round	Up to 5% of electric commodity portion of bill	$7/kW per month for monthly average peak kW minus FSL, paid year-round				$.20/kWh bill credit on amount of reduction below 10-day baseline	$.10/kWh bill credit on amount of reduction below 10-day baseline
	Incentive Payment Guarantee									
	Avoid Outage							exempt from rolling blackouts		
	Metering Subsidy			Free meter						
	Bill Protection									
	Other								Air quality compliance runs exempted	
9	Payment channel									
	Bill Credit				√	√	√		√	√
	Check									
	Rate Discount	√	√	√						
	Other							√		
10	Penalty for Non-compliance									
	$/kW									
	$/kWh	$8.40/kWh; $4.20/kWh if customer complied all previous year	<2kV: $9.30/kWh 2-50 kV: $9.01/kWh >50 kV:$7.20/kWh		$6 per kWh for energy use above fixed service level during curtailment event			$6 per kWh for energy use above required reduction		
	Removed from rate/program							After failure to comply on two events in a year		After failure to comply with at least 5 events in a summer
	Subject to Rolling Blackouts							After failure to comply on two events in a year		
	Other			higher energy prices during peak period					none	Repay meter installation cost, if applicable
11	Penalty Adjudication/Waiver Process									
	Description									
12	Test Event Actions									
	Customer Requirements	Verify Communication		Annual mandatory day (30 minutes duration)						
	Utility Actions	up to 5 tests per year; at least 6 every 3 years		Monthly data process & contact closure test	Monthly communication test			Monthly communication test		Monthly communication test

	Revised 12/13/04			Traditional IRs			BIP				
			PG&E Sched 19/20	**SCE I-6**	**SDG&E AL TOU CP**	**PG&E**	**SCE**	**SDG&E**	**OBMC/ POBMC**	**RBRP**	**SLRP**
	2004 service accounts (July)		**102**	**515**	**63**	**17**	**61**	**0**	**49**	**65**	**16**
13	Event Call Criteria										
		Stage 2 Emergency	√	√	√		----------------- √ -----------------				
		Stage 3 Emergency							√	√	
		Commodity Price Point			1.8 cent signal price						
		Other	System Emergency		3824 MW system peak exceeded >15 minutes, or local utility emergency		---------- System Emergency ----------		Rolling blackouts/ rotating outages	Rolling blackouts/ rotating outages	pre-scheduled weekdays from June 1 to Sept. 30
14	Event Period Definition										
		Description	CAISO Stage 2, System Emergency	CAISO Stage 2, System Emergency	CAISO Stage 2, System Emergency, 3824 MW SDG&E peak		CAISO Stage 2, System Emergency		no limit	no limit	pre-defined 4-hour periods starting at 8 AM, noon, and 4 PM
15	Maximum # of Hours/Event										
		Hours		----------------------- 6 -----------------------			---------------- 4 ----------------		no limit	no limit	Participants must identify a specific 4 hour time period, up to 3 times per week, but no more than 2 times in the same time period
16	Maximum # of Events/Week or Day										
		Events	1 per day, 4 per week	1 per day, 4 per week			------------ 1 per day ------------		no limit	no limit	3 per week
17	Maximum # of Events, Hours/Month										
		Events		40 hours	40 hours		---------------- 10 ----------------		no limit	no limit	3 per week
18	Maximum # of Events/Season										
		Events							no limit	no limit	3 per week, June-Sept.
19	Maximum # of Events/Year										
		Events	30 events, 100 hours	25 events, 150 hours	120 hours		------------ 120 hours ------------		no limit	no limit	3 per week, June-Sept.
20	Notification Advance Time Period										
		Minutes/Hours	30 minutes	30 minutes	15 min		------------ 30 minutes ------------		15 min	15 min	none; pre-scheduled
21	Notification Method/Channel										
		Fax	Alarmed Fax								
		Auto Telephone					√	√	√	√	
		Live Telephone	√	√			√				
		Pager			√	InterAct II		√	InterAct II	√	InterAct II
		Email	√		√	InterAct II		√	InterAct II	√	InterAct II
		Internet						√	√	√	
		Other	Envoy system used	RTU							

	Revised 12/13/04	Traditional IRs			BIP					
		PG&E Sched 19/20	SCE I-6	SDG&E AL TOU CP	PG&E	SCE	SDG&E	OBMC/ POBMC	RBRP	SLRP
	2004 service accounts (July)	**102**	**515**	**63**	**17**	**61**	**0**	**49**	**65**	**16**
22	Response Confirmation Requirement					None				
	Return Email	√			√		√	√		
	Web Site Logon									
	Live Telephone									
	2-Way Pager									
	Other								IVR response to confirm notification received	None
23	Tracking Hardware/Software									
	RTU		√							
	Web Networking (InterAct, etc.)				√			√		
	Other									
24	Metering Requirements									
	Interval - Total Load	All Schedule 19/20 customers must have interval meters	RTU	Free interval data meter for participants	Interval meter required, participants can have one installed at no charge, but are then required to remain in the program for a full year			Customers must pay for and install metering, communications eqpt.	Free interval data meter and communications link for participants	Free interval data meter for participants
	Other Advanced - Total Load									
	Load Submetering									
25	Meter & Account Aggregation Allowed									
	Within Customer/Among Accounts		√							
	Among Customers									
	Other							Accounts on same circuit		
26	Technical Assistance Options									
	DR Tech Assist									
	Energy Audit									
	Other							Utility will assist in coordinating load red'n	Site survey - generator data, connection	
27	M&V, Survey Participation Requirement									
	Description									
28	Participation Fees/Customer Actions Required									
	Metering							Customers must pay for and install metering, communications eqpt.	Free interval data meter and communications link for participants	
	Administrative Processing							Customer must file OBMC Plan		Customer must choose scheduled times
	Other									
29	Sign-up & Renewal Periods/Cycles									
	Sign-up	Any time	Any time	Any time	Any time	Any time	Any time	Any time	Any time	Any time
	Renewal	Customers can increase FSL in November; PG&E may require up to three years' written notice to change from non-firm to firm service	Annual opt-out/FSL increase/decrease in November					Customers are required to update their OBMC Plans by March 15 of each year		November is opt-out month

APPENDIX H.2
INTERRUPTIBLE EVENT HISTORY

This appendix provides a summary of the event history for reliability-triggered interruptible programs. It is compiled from utility monthly event reports used to track the following data:

- Accounts enrolled
- Total demand impact as per enrollment data provided in contracts and other enrollment forms
- Number of events, by program
- MW impacts achieved (enrollment MW, not peak-coincident MW)
- Number of accounts responding to events
- Minimum MW achieved where >1 event called (to get a sense of event response impact swings)
- Minimum number of accounts responding where >1 event called.

The data are nearly complete, but the reader will note that data were not available for every instance of these parameters and are still being sought; where that is the case a question mark is indicated. Also, some 2004 data still need to be verified as being through July.

SUMMARY

California Interruptible Program History 2000-2004

2000

Utility	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events Total/All Called Rates	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
		Reliability Triggered Summary					
PG&E	412	169	23	568	214	92	44
SCE	1615	1451	21	1235	832	795	350
SDG&E	78	159	53	0	0	0	0
Total	**2105**	**1779**	**97**	**1803**	**1046**	**887**	**394**

Traditional Interruptible Programs

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	412	169	23	568	214	92	44
SCE	1615	1451	21	1235	832	795	350
SDG&E	78	159	53	?	?	?	?
Total	**2105**	**1779**	**97**	**1803**	**1046**	**887**	**394**

Base Interruptible Program (BIP)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	0	0	0	0	0	0	0
SCE	0	0	0	0	0	0	0
SDG&E	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Scheduled Load Reduction Program (SLRP)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	0	0	0	0	0	0	0
SCE	0	0	0	0	0	0	0
SDG&E	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Optional Binding Mandatory Curtailment Program (OBMC)

	MW Enrolled Year-end (6)	Accts Enrolled (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	0	0	0	0	0	0	0
SCE	0	0	0	0	0	0	0
SDG&E	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**

San Diego Rolling Blackout Response Program (RBRP) (5)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
SDG&E	0	0	0	0	0	0	0

? = Data unavailable or pending update
n/a = Not applicable due to no events being called.
(1) Accts = utility service accounts, which is not the same as customers
(3) OBMC MWs are forecast at the 5% load reduction level, considered the most likely to occur.
(5) San Diego Program to use back-up generators to avoid rotating blackouts per D.01-06-009
(6) The maximum load reduction is reflected.

SUMMARY

California Interruptible Program History 2000-2004

2001

Reliability Triggered Summary

Utility	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events Total/All Called Rates	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	333	169	25	337	170	46	27
SCE	774	626	40	947	402	14	316
SDG&E	137	95	25	0	0	0	0
Total	**1244**	**890**	**90**	**1284**	**572**	**60**	**343**

Traditional Interruptible Programs

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	304	126	25	337	170	46	27
SCE	702	591	38	947	402	14	316
SDG&E	122	74	25	?	?	?	?
Total	**1128**	**791**	**88**	**1284**	**572**	**60**	**343**

Base Interruptible Program (BIP)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	0	0	0	0	0	0	0
SCE	3	7	2	?	?	?	?
SDG&E	0	0	0	0	0	0	0
Total	**3**	**7**	**2**	**0**	**0**	**0**	**0**

Scheduled Load Reduction Program (SLRP)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	0	0	0	n/a	n/a	n/a	n/a
SCE	4	10	0	n/a	n/a	n/a	n/a
SDG&E	2	1	0	n/a	n/a	n/a	n/a
Total	**6**	**11**	**0**		**0**		**0**

Optional Binding Mandatory Curtailment Program (OBMC)

	MW Enrolled Year-end (6)	Accts Enrolled (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	29	43	0	n/a	n/a	n/a	n/a
SCE	65	18	0	n/a	n/a	n/a	n/a
SDG&E	0.8	1	0	n/a	n/a	n/a	n/a
Total	**95**	**62**	**0**	**0**	**0**	**0**	**0**

San Diego Rolling Blackout Response Program (RBRP) (5)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
SDG&E	12	19	0	0	0	0	0

? = Data unavailable or pending update

n/a = Not applicable due to no events being called.

(1) Accts = utility service accounts, which is not the same as customers

(3) OBMC MWs are forecast at the 5% load reduction level, considered the most likely to occur.

(5) San Diego Program to use back-up generators to avoid rotating blackouts per D.01-06-009

(6) The maximum load reduction is reflected.

SUMMARY

California Interruptible Program History 2000-2004

2002

Emergency Triggered Summary

Utility	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events Total/All Called Rates	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	344	160	19	0	1	0.04	1
SCE	616	625	6	527	436	491	422
SDG&E	91	126	1	0	4	0	0
Total	**1051**	**911**	**26**	**527**	**441**	**491**	**423**

Traditional Interruptible Programs

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	319	107	1	n/a - Footnote 7	n/a - Footnote 7		
SCE	573	553	3	497	436	468	422
SDG&E	21	63	1	n/a	n/a	n/a	n/a
Total	**913**	**723**	**5**	**497**	**436**	**468**	**422**

Base Interruptible Program (BIP)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	13	14	1	n/a - Footnote 7	n/a - Footnote 7	n/a	n/a
SCE	30	40	3	30	?	23	?
SDG&E	0	0	0	0	4	0	0
Total	**43**	**54**	**4**	**30**	**4**	**23**	**0**

Scheduled Load Reduction Program (SLRP)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	0	1	17	0.2	1	0.04	1
SCE	4	18	0?	n/a?	n/a?	n/a?	n/a?
SDG&E	0	0	0	0	0	0	0
Total	**4**	**19**	**17**		**1**		**1**

Optional Binding Mandatory Curtailment Program (OBMC)

	MW Enrolled Year-end (6)	Accts Enrolled (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	12	38	0	n/a	n/a	n/a	n/a
SCE	9	14	0?	n/a?	n/a?	n/a?	n/a?
SDG&E	0	0	0	0	0	0	0
Total	**21**	**52**	**0**	**0**	**0**	**0**	**0**

San Diego Rolling Blackout Response Program (RBRP) (5)

	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
SDG&E	70	63	0	0	0	0	0

? = Data unavailable or pending update
n/a = Not applicable due to no events being called.
(1) Accts = utility service accounts, which is not the same as customers
(3) OBMC MWs are forecast at the 5% load reduction level, considered the most likely to occur.
(5) San Diego Program to use back-up generators to avoid rotating blackouts per D.01-06-009
(6) The maximum load reduction is reflected.
(7) Event terminated prior to minimum notification time.

SUMMARY

California Interruptible Program History 2000-2004

2003

Utility	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events Total/All Called Rates	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
		Reliability Triggered Summary					
PG&E	330	153	0	0	0	0	0
SCE	738	612	0	0	0	0	0
SDG&E	88	128	4	0	0	0	0
Total	**1156**	**893**	**4**	**0**	**0**	**0**	**0**

		Traditional Interruptible Programs					
	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	304	104	0?	n/a?	n/a?	n/a?	n/a?
SCE	661	523	0	n/a	n/a	n/a	n/a
SDG&E	21	63	4	?	?	?	?
Total	**985**	**690**	**4**	**0**	**0**	**0**	**0**

		Base Interruptible Program (BIP)					
	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	13	13	0?	n/a?	n/a?	n/a?	n/a?
SCE	65	60	0	n/a	n/a	n/a	n/a
SDG&E	0	0	0	0	0	0	0
Total	**78**	**73**	**0**	**0**	**0**	**0**	**0**

		Scheduled Load Reduction Program (SLRP)					
	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	0.1	1	0?	n/a?	n/a?	n/a?	n/a?
SCE	4	15	0	n/a	n/a	n/a	n/a
SDG&E	0	0	0	0	0	0	0
Total	**4**	**16**			**0**		**0**

	Optional Binding Mandatory Curtailment Program (OBMC)						
	MW Enrolled Year-end (6)	Accts Enrolled (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	13	35	0	n/a	n/a	n/a	n/a
SCE	9	14	0	n/a	n/a	n/a	n/a
SDG&E	0	0	0	0	0	0	0
Total	**22**	**49**	**0**	**0**	**0**	**0**	**0**

	San Diego Rolling Blackout Response Program (RBRP) (5)						
	MW Enrolled Year-end (6)	Accts Enrolled Yr-end (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
SDG&E	67	65	0	0	0	0	0

? = Data unavailable or pending update
n/a = Not applicable due to no events being called.
(1) Accts = utility service accounts, which is not the same as customers

(3) OBMC MWs are forecast at the 5% load reduction level, considered the most likely to occur.
(5) San Diego Program to use back-up generators to avoid rotating blackouts per D.01-06-009
(6) The maximum load reduction is reflected.

SUMMARY

California Interruptible Program History 2000-2004

2004 (through July)

Reliability Triggered Summary

Utility	MW Enrolled thru JULY (6)	Accts Enrolled thru JULY (1)	# Events Total/All Called Rates	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	378	156	0	0	0	0	0
SCE	724	604	2	615	0	160	0
SDG&E	85	128	3	4	45	2	0
Total	**1187**	**888**	**5**	**619**	**45**	**162**	**0**

Traditional Interruptible Programs

	MW Enrolled thru JULY (6)	Accts Enrolled thru JULY (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	349	102	0?	n/a?	n/a?	n/a?	n/a?
SCE	640	515	2	615	?	160	?
SDG&E	25	63	3	4	45	2	n/a
Total	**1014**	**680**	**5**	**619**	**45**	**162**	**0**

Base Interruptible Program (BIP)

	MW Enrolled thru JULY (6)	Accts Enrolled thru JULY (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	16	17	0?	n/a?	n/a?	n/a?	n/a?
SCE	73	61	0	n/a	n/a	n/a	n/a
SDG&E	0	0	0	0	0	0	0
Total	**89**	**78**	**0**	**0**	**0**	**0**	**0**

Scheduled Load Reduction Program (SLRP)

	MW Enrolled thru JULY (6)	Accts Enrolled thru JULY (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	0	1	0?	n/a?	n/a?	n/a?	n/a?
SCE	4	15	0?	n/a?	n/a?	n/a?	n/a?
SDG&E	0	0	0	0	0	0	0
Total	**4**	**16**	**0**		**0**		**0**

Optional Binding Mandatory Curtailment Program (OBMC)

	MW Enrolled thru JULY (6)	Accts Enrolled thru JULY (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
PG&E	13	36	0	n/a	n/a	n/a	n/a
SCE	8	13	0?	n/a?	n/a?	n/a?	n/a?
SDG&E	0	0	0	0	0	0	0
Total	**21**	**49**	**0**	**0**	**0**	**0**	**0**

San Diego Rolling Blackout Response Program (RBRP) (5)

	MW Enrolled thru JULY (6)	Accts Enrolled thru JULY (1)	# Events This Rate	Max MW Achieved	Max # of Accts Responding	Min MW Achieved (if >1 Event)	Min # of Accts Responding
SDG&E	60	65	0	0	0	0	0

? = Data unavailable or pending update
n/a = Not applicable due to no events being called.
(1) Accts = utility service accounts, which is not the same as customers
(3) OBMC MWs are forecast at the 5% load reduction level, considered the most likely to occur.
(5) San Diego Program to use back-up generators to avoid rotating blackouts per D.01-06-009
(6) The maximum load reduction is reflected.

APPENDIX I
U.S. DR PROGRAM COMPARISON MATRIX

APPENDIX I
REVIEW OF NON-CALIFORNIA DEMAND RESPONSE PROGRAMS

This appendix contains information on 63 programs collected from 30 electricity wholesale and retail organizations (primarily investor-owned utilities but also a number of ISOs) in the United States that offer demand response programs. It is not exhaustive,[1] but it does cover most of the major geographic areas of the U.S. The list represents most of the forms of demand response programs, ranging from traditional interruptible types of programs, that address resource needs through direct load control and curtailment events (whether reliability triggered or cost-triggered), to more recently designed programs that trigger primarily on price alone.

The tables are organized as follows:

Exhibit I.1: Index of Programs by Size Eligibility Criteria
Exhibit I.2: Index of Programs by Event Trigger
Exhibit I.3: Non-California DR Programs

A sample of the C&I programs having similarities to California's demand response programs was identified and their program managers contacted to obtain additional information and insights on the programs. The findings from those program manager interviews are summarized at the bottom of their organization's program listing(s).

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[1] In particular, residential direct load control programs are under-represented.

Exhibit I.1
Index of Programs by Size Eligibility Criteria

Program Sponsor:	Eligible load	<200kW Minimum Impact Allowed	>200kW Minimum Impact Required
AEP Emergency Curtailable Service Program	>3 MW		x
AEP MarketChoice Program	>1 MW		x
AEP Price Curtailable Service Program	>3 MW		x
Allegheny Power Generation Buy-Back Program	>1 MW; however, customers able to curtail "significant" amounts of load will not be turned away According to the tariff >3 MW		x
AmerenEnergy Energy Exchange	>500 kW		x
Bonneville Power Administration Demand Exchange	>1 MW Smaller loads can be aggregated		x
Central Hudson Gas & Electric Day-Ahead Demand Response Program	>1 MW		x
Central Hudson Gas & Electric Emergency Demand Response Program	>100 kW	x	
Cinergy PowerShare Pricing Program	>500 kW		x
Commonwealth Edison Energy Cooperative	Not specified	x	
Commonwealth Edison Voluntary Load Reduction Program	>10 kW or 5% of maximum peak load, whichever is greater	x	
Consolidated Edison Day-Ahead Demand Reduction Program	>100 kW	x	
Consolidated Edison Distribution Load Relief Program	>50 kW	x	
Consolidated Edison Emergency Demand Response Program	>100 kW	x	
Consolidated Edison Installed Capacity Program	>100 kW	x	
Consolidated Edison Voluntary Load Reduction Program	>100 kW	x	
Dominion Virginia Power Economic Load Curtailment Program	>1 MW and able to curtail at least 500 kWh		x
Dominion Virginia Power Real Time Program	>5 MW		x
Duquesne Light Company Energy Exchange	>500 kW		x
Entergy Experimental Energy Reduction Program (EER)	>150 kW	x	
Entergy Market Value Call Option Service (MVCO)	Not specified, Enetergy customer submits curtailable amount with application	x	
Entergy Market Valued Energy Option (MVEO)	Not specified, Enetergy customer submits curtailable amount with application	x	
First Energy Voluntary Power Curtailment Program	>1 MW		x
First Energy Experimental Real Time Pricing Program	Max 500 MW of demand		x
Georgia Power Daily Energy Credit Program	>500 kW		x
Georgia Power Real Time Pricing Program	>250 kW - Day-Ahead Option >5 MW - Hour-Ahead Option		x
Idaho Power Energy Exchange Program	>1 MW		x
ISO-NE Demand Response Program (Class 1)	100 kW - 5 MW Aggregation of load by the enrolling participant is allowed	x	
ISO-NE Price Response Program (Class 2)	100 kW - 5 MW Aggregation of load by the enrolling participant is allowed	x	
ISO-NE Day Ahead Demand Response	> 1 MW (aggregation is allowed)		x
ISO-NE Real Time Demand Response	100 kW - 5 MW (aggregation is allowed)	x	

Program Sponsor:	Eligible load	<200kW Minimum Impact Allowed	>200kW Minimum Impact Required
ISO-NE **Real Time Price Response**	100 kW - 5 MW (aggregation is allowed)	x	
ISO-NE **Real Time Profiled Response**	100 kW - 5 MW (aggregation is allowed)	x	
Kansas City Power & Light Peak Load Curtailment Program	>200 kW	x	
Kansas City Power & Light Real Time Pricing Program	>500 kW		x
Kansas City Power & Light Voluntary Load Reduction Program	>100 kW	x	
Lincoln Electric System Load Purchase Program	>100 kW	x	
Lincoln Electric **Daily Curtailment**	>100 kW	x	
Lincoln Electric **Seasonal Curtailment**	>100 kW	x	
Long Island Power Authority Peak Reduction Program	>50 kW	x	
NYISO Day-Ahead Demand Response Program	>1 MW per NYISO Zone (may aggregate within zones)		x
NYISO Emergency Demand Response Program	>100 kW per NYISO Zone (may aggregate within zones)	x	
NYISO **ICAP/SCR Program**	>100 kW per NYISO Zone (may aggregate within zones)	x	
New York Power Authority Peak Load Management Program	No minimum load reduction commitment, but the amount must be measurable (generally 100 kW)	x	
Otter Tail Power Real Time Pricing Program	>200 kW	x	
Otter Tail Power Released Energy Access Program	>1 MW		x
PacifiCorp Energy Exchange Program	>1 MW		x
PECO Voluntary Load Reduction Program	>250 kW		x
PECO **Curtailment HT Rider**	>1 MW		x
Pepco Curtailable Load Program	>50 kW	x	
PJM Day-Ahead & Real Time Economic Load Response Program	PJM members are required to participate		
PJM Emergency Load Response Program	>100 kW - PJM members are required to participate	x	
Portland General Electric Demand Buy Back Program	>250 kW		x
PPL Demand Side Initiative Rider	>1 MW		x
Sacramento Municipal Utility District PowerDirect	>100 kW	x	
Sacramento Municipal Utility District PowerNet	>75 kW	x	
WE Energies **Dollars for Power Program**	>50 kW	x	
WE Energies **Experimental Energy Cooperative Curtailable**	>300 kW for customers w/ avg. monthly demand >3000kw or 100 kW or 10% of montly load for customers with demand<3000kw		x
WE Energies **General Primary Service – Curtailable**	>500 kW		x
WE Energies **Power Market Incentives Program**	>500 kW The Pool option allows >100 kW customers to aggregate their loads to at least 500 kW		x
Xcel Energy Peak Control (MN, ND, SD, WI, MI)	>50 kW	x	
Xcel Energy Experimental Industrial Interruptible Rate Rider (TX)	>=1000 kW		x
Xcel Energy Transmission, Primary, Secondary Interruptible Rate (CO)	>=500 kW		x

Exhibit I.2
Index of Programs by Event Trigger

Program Sponsor:	Call Criteria	Price	Demand	Price/ Demand
AEP Emergency Curtailable Service Program	System Contingencies		x	
AEP MarketChoice Program	N/A - Real Time Pricing (above or below baseline priced at hourly market prices)	x		
AEP Price Curtailable Service Program	High market prices	x		
Allegheny Power Generation Buy-Back Program	High demand &/or market prices			x
AmerenEnergy Energy Exchange	High demand &/or market prices			x
Bonneville Power Administration Demand Exchange	High demand &/or market prices			x
Central Hudson Gas & Electric Day-Ahead Demand Response Program	High demand &/or market prices			x
Central Hudson Gas & Electric Emergency Demand Response Program	Emergency situation declared by NYISO		x	
Cinergy PowerShare Pricing Program	High demand &/or market prices			x
Commonwealth Edison Energy Cooperative	High demand &/or market prices			x
Commonwealth Edison Voluntary Load Reduction Program	High demand &/or market prices			x
Consolidated Edison Day-Ahead Demand Reduction Program	Wholesale prices exceed a pre-determined strike price	x		
Consolidated Edison Distribution Load Relief Program	Times of risk or reduced reliability		x	
Consolidated Edison Emergency Demand Response Program	Power shortages or emergencies declared by NYISO		x	
Consolidated Edison Installed Capacity Program	Follows terms of NYISO Installed Capacity Procedures for Special Case Resources		x	
Consolidated Edison Voluntary Load Reduction Program	Local power shortages or emergencies declared by ConEd		x	
Dominion Virginia Power Economic Load Curtailment Program	Whenever company elects		x	
Dominion Virginia Power Real Time Program	N/A - Real Time Pricing	x		
Duquesne Light Company Energy Exchange	Wholesale prices exceed a pre-determined strike price	x		
Entergy Experimental Energy Reduction Program (EER)	Constrained Supply		x	
Entergy Market Value Call Option Service (MVCO)	High demand &/or market prices			x
Entergy Market Valued Energy Option (MVEO)	High demand &/or market prices			x
First Energy Voluntary Power Curtailment Program	High demand &/or market prices			x
First Energy Experimental Real Time Pricing Program	N/A - Real Time Pricing	x		
Georgia Power Daily Energy Credit Program	High demand &/or market prices			x
Georgia Power Real Time Pricing Program	N/A - Real Time Pricing	x		
Idaho Power Energy Exchange Program	High demand &/or market prices			x
ISO-NE Demand Response Program (Class 1)	10 Minute Operating Reserve Deficiency		x	
ISO-NE Price Response Program (Class 2)	Hourly Energy Clearing Price >= $100/MWh	x		
ISO-NE Day Ahead Demand Response	Respond to ISO Control Room Request		x	
ISO-NE Real Time Demand Response	Respond to ISO Control Room Request		x	
ISO-NE Real Time Price Response	The forecast hourly Zonal Price is >= $100/MWh	x		
ISO-NE Real Time Profiled Response	Respond to ISO Control Room Request		x	
Kansas City Power & Light Peak Load Curtailment Program	High demand &/or market prices			x
Kansas City Power & Light Real Time Pricing Program	N/A - Real Time Pricing	x		
Kansas City Power & Light Voluntary Load Reduction Program	High demand &/or market prices			x
Lincoln Electric System Load Purchase Program	High demand &/or market prices			x
Lincoln Electric Daily Curtailment	High demand &/or market prices			x
Lincoln Electric Seasonal Curtailment	High demand &/or market prices			x
Long Island Power Authority Peak Reduction Program	High demand &/or market prices			x
NYISO Day-Ahead Demand Response Program	Curtailment opportunities based on customer bids not system conditions.		x	
NYISO Emergency Demand Response Program	Operating Reserves Deficiency or other emergency state		x	
NYISO ICAP/SCR Program	Operating Reserves Deficiency or other emergency state		x	
New York Power Authority Peak Load Management Program	High demand &/or market prices			x
Otter Tail Power Real Time Pricing Program	N/A - Real Time Pricing	x		
Otter Tail Power Released Energy Access Program	High demand &/or market prices			x
PacifiCorp Energy Exchange Program	High demand &/or market prices			x
PECO Voluntary Load Reduction Program	High demand &/or market prices			x

Program Sponsor:	Call Criteria	Price	Demand	Price/ Demand
PECO **Curtailment HT Rider**	Any Prodcution, Transmission, or distirbution capacity limitations exist.		x	
Pepco Curtailable Load Program	High demand &/or market prices			x
PJM Day-Ahead & Real Time Economic Load Response Program	High LMP		x	
PJM Emergency Load Response Program	Declaration of Maximum Emergency Generation and prior to the implementation of Active Load Management		x	
Portland General Electric Demand Buy Back Program	High demand &/or market prices			x
PPL Demand Side Initiative Rider	N/A - Real Time Pricing	x		
Sacramento Municipal Utility District PowerDirect	High demand &/or market prices Customers specify predetermined weekly time period, price, and load reduction			x
Sacramento Municipal Utility District PowerNet	High demand &/or market prices Customers specify predetermined weekly time period, price, and load reduction			x
WE Energies **Dollars for Power Program**	Wholesale prices exceed pre-established bid prices	x		
WE Energies **Experimental Energy Cooperative Curtailable**	High demand &/or market prices			x
WE Energies **General Primary Service – Curtailable**	High demand &/or market prices			x
WE Energies **Power Market Incentives Program**	Wholesale prices exceed pre-established bid prices	x		
Xcel Energy Peak Control (MN, ND, SD, WI, MI)	Forecasted load above MAPP Level.		x	
Xcel Energy Experimental Industrial Interruptible Rate Rider (TX)	Needed for System Relief		x	
Xcel Energy Transmission, Primary, Secondary Interruptible Rate (CO)	Needed for System Relief		x	

Exhibit I.3
Non-California DR Programs

Program Sponsor:	AEP Emergency Curtailable Service Program	AEP MarketChoice Program	AEP Price Curtailable Service Program	Allegheny Power Generation Buy-Back Program
Period	7 am - 11 pm Weekdays	Weekdays - All Year	Weekdays - All Year	Weekday On-Peak
Eligible participant	C&I Customers	Retail non-residential customers	C&I Customers	C&I Customers
Eligible load	>3 MW	>1 MW	>3 MW	>1 MW; however, customers able to curtail "significant" amounts of load will not be turned away According to the tariff >3 MW
Call criteria	System Contingencies	N/A - Real Time Pricing (above or below baseline priced at hourly market prices)	High market prices	High demand &/or market prices
Response period	30 minutes	By 2 PM each day, hourly energy prices will be posted for the following day	30 minutes	Day-Of - Minimum of 2 hours Also a Day- Ahead option
Respondent option	Mandatory - Penalties are assessed for non-compliance and customers can be removed from the program after 2 non-compliance events in a 12 month period	Voluntary	Mandatory - Penalties are assessed for non-compliance and customers can be removed from the program after 2 non-compliance events in a 12 month period	Voluntary
Duration	Limited to 50 hours/season Option A - 4 hours max Option B - 8 hours max	N/A - Real Time Pricing	Customer specifies the maximum number of days they would be willing to curtail and chooses a max of 4, 8, or 16 hours	Minimum of 1 hour and may extend through the end of the on-peak period
Compensation	Option A - $0.35/kWh reduction Option B - $0.50/kWh reduction	Customers are credited or charged, based upon market price, for usage below or above CBL	Customer specifies minimum price for the load they curtail and receives a minimum of 2 hours credit per curtailment event	Customer-specific - 50% - 90% of the wholesale price of power
Baseline criteria	Typical On-Peak Demand	One year of hourly kWh and associated billing determinants	Typical Demand	Typical Demand
Performance Measure	ECS Contract Capacity = Typical On-Peak Demand - Non-ECS Demand	Baseline difference	Typical Demand - Specified curtailment	Baseline difference
Payment channel	AEP -> Customer via monthly credit	AEP -> Customer	AEP -> Customer via monthly credit	AP -> Customer via credit on next bill
Metering method	Interval Meter	Hourly-interval demand meter accessible by phone line	Interval Meter	Interval Meter
Notification method	Customer chooses - Internet, email, phone, pager	Customer chooses - Internet, email, phone, pager	Customer chooses - Internet, email, phone, pager	Customer selects preferred method of notification - electronic protocol, telephone, pager, and/or fax
Software requirement	None specified	None specified	None specified	None specified
Program fees	None specified	Monthly Program Charge of $100 Increases to $310 if customer wants AEP to provide a PC workstation capable of providing price & load monitoring capability If the proper meter is not in place, the incremental cost of upgrading to the new meter	None specified	None specified
Year Program Began				
Customer Accounts Enrolled - 2004				
MW Enrolled - 2004				
% of Enrolled MW Shed During Events				
Event Impacts Met Expectations?				
Strengths of Program				
Weaknesses of Program				
What Would Do Differently If Starting Over				
Nuances Not Understood by Others				
Key Lessons Learned				
Predessor Program				

Exhibit I.3
Non-California DR Programs

Program Sponsor:	AmerenEnergy Energy Exchange	Bonneville Power Administration Demand Exchange	Central Hudson Gas & Electric Day-Ahead Demand Response Program	Central Hudson Gas & Electric Emergency Demand Response Program
Period	Weekday On-Peak	Weekday On-Peak	May 1, 2001 - Oct 31, 2003	May 1, 2001 - Oct 31, 2002
Eligible participant	C&I Customers	C&I and wholesale utility customers	C&I Customers	C&I Customers
Eligible load	>500 kW	>1 MW Smaller loads can be aggregated	>1 MW	>100 kW
Call criteria	High demand &/or market prices	High demand &/or market prices	High demand &/or market prices	Emergency situation declared by NYISO
Response period	Customers are given a password to access the website and view the offers for the day or next day on line	Customers access the website and view the offers for the day, next day, or two days ahead on-line	Customer provides a bid 2 days prior to dispatch day - CHG&E notifies customers of accepted bids by 3 PM on the day before the dispatch day	2 hours
Respondent option	Voluntary	Customer has the option to bid a curtailment; however, if a customer's bid is accepted by BPA, both parties are committed to settle at that price	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties	Voluntary
Duration	Varies	Varies	As bid	Four hour minimum call
Compensation	Credit is calculated based upon customer curtailment * price offer	Credit is calculated based upon customer curtailment * price offer	Customers are paid their bid kWs times 90% of the dollar per kW received by CHG&E from NYISO	Greater of Real Time Locational Based Marginal Price (LBMP) or $500/MWh Participants are paid 90% of the amount NYISO pays Central Hudson
Baseline criteria	Typical Demand	Typical Demand calculated by Apogee load analysis models	5 highest of 10 prior days	5 highest of 10 prior days
Performance Measure	Baseline difference	Baseline difference	Baseline difference	Baseline difference
Payment channel	AE -> Customer via monthly credit or check	BPA -> Customer or Aggregator	NYISO -> CHG&E -> customer	NYISO -> CHG&E -> customer
Metering method	Interval meter with communications equipment	Interval meter with communications equipment	Interval meter	Interval meter
Notification method	Notice of curtailment offers come via fax - customer then accesses AmerenEnergy's website to view price offers	Internet	Day Ahead notification over internet	2 hour prior notice via the internet, email, phone, pager notification
Software requirement	Internet (Also uses Abacus, in-house software for interval usage information reports to customers)	Internet	Internet	Internet
Program fees	$4.00 - $21.00 per month to manage interval meter based upon tariff rate	None specified	None specified	None specified
Year Program Began	2000			
Customer Accounts Enrolled - 2004	120			
MW Enrolled - 2004	240			
% of Enrolled MW Shed During Events	75-100%			
Event Impacts Met Expectations?	Yes			
Strengths of Program	No metering or communications fees. Abacus software system. Simple contract. No sunset. No penalties.			
Weaknesses of Program	Inactivity. Internal admin process. Software functionality. Not enough dollar incentive for customers.			
What Would Do Differently If Starting Over	Improve internal admin process.			
Nuances Not Understood by Others	Market prices not high enough in last 2 yrs to call program.			
Key Lessons Learned	No big lessons due to inactivity. Political pressure from legislature to continue offering program but minimal cost to do so. Major benefit is capacity credit allowed toward MAIN 18% reserve margin.			
Predessor Program			x	x

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Cinergy PowerShare Pricing Program	Commonwealth Edison Energy Cooperative	Commonwealth Edison Voluntary Load Reduction Program	Consolidated Edison Day-Ahead Demand Reduction Program
Period	Weekday On-Peak (June - Sept)	Weekday On-Peak (June - Sept)	Weekday On-Peak (June - Sept)	Weekdays through Oct 31, 2004
Eligible participant	C&I Customers	Non-residential customers	Non-residential customers	C&I Customers
Eligible load	>500 kW	Not specified	>10 kW or 5% of maximum peak load, whichever is greater	>100 kW
Call criteria	High demand &/or market prices	High demand &/or market prices	High demand &/or market prices	Wholesale prices exceed a pre-determined strike price
Response period	Customers access the website and view the offers for the day, next day, or two days ahead on-line	Minimum of 1 hour	Minimum of 1 hour	Customer provides a bid 2 days prior to dispatch day - ConEd notifies customers of accepted bids by 3 PM on the day before the dispatch day
Respondent option	Customers select the strike price, number of events per summer, and amount of load reduction to suit their needs - They must participate when called - Quote option also exists	No penalties for non-compliance for specific events; however, non-compliance reduces seasonal average curtailment level which reduces payment levels	Voluntary	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties (the greater of 110% of the real time or day-ahead wholesale price of electricity during the event)
Duration	Varies	2 - 6 hours No more than 3 consecutive days out of 5 & 120 hours per season	Minimum of 2 hours - Maximum of 7 hours No more than 20 events or 100 hours per year	Varies
Compensation	Guaranteed monthly premium during the four active months	$/kW payment (averages $35) based upon cooperative performance If no curtailment event is requested, participants will be compensated at contracted level	Energy Component of at least $0.15 per kWh curtailed + Delivery Services component, the value of which depends on system conditions	90% of the DADRP payment that ConEd receives from NYISO Customers are also guaranteed of their full load reduction costs through an adder on their bid price
Baseline criteria	Typical Demand	Typical Demand calculated through regressions of previous load data, temperature, day of week, and cloud cover	Typical Demand calculated through regressions of previous load data, temperature, day of week, and cloud cover	Typical Demand calculated according to NYISO methodology (5 highest of 10 prior days)
Performance Measure	Baseline difference	Baseline difference	Baseline difference	Baseline difference
Payment channel	Cinergy -> Customer via monthly premium and energy credits	ComEd -> Customer via lump sum payment by the end of the year	ComEd -> Customer via cash or billing credits by the end of the year	NYISO -> ConEd -> Customer
Metering method	Interval Meter	Interval data recording meter with dedicated phone line	Interval data recording meters	Interval meter with phone line
Notification method	Internet	Phone, pager, e-mail, or fax	Phone, pager, e-mail, or fax	e-mail
Software requirement	Internet	EnergyTracker (ComEd)	None specified	e-mail access is required
Program fees	None specified	None specified	None specified	None specified
Year Program Began	2000			
Customer Accounts Enrolled - 2004	530			
MW Enrolled - 2004	170			
% of Enrolled MW Shed During Events	0.8			
Event Impacts Met Expectations?	Yes			
Strengths of Program	Interaction with account management group - strong customer relationships. Annual test run. Call option locks in load at beginning of season. Technical auditing services offered. Web site capabilities.			
Weaknesses of Program	Low premium levels. Call option customers disappointed with levels			
What Would Do Differently If Starting Over	Make a voluntary bid nomination program instead of contract/mandatory program.			
Nuances Not Understood by Others	Program is basic. Web site features a plus.			
Key Lessons Learned	Smaller customers (100-300kW) and being able to accommodate them would be a real benefit.			
Predessor Program	x			

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Consolidated Edison Distribution Load Relief Program	Consolidated Edison Emergency Demand Response Program	Consolidated Edison Installed Capacity Program	Consolidated Edison Voluntary Load Reduction Program
Period	7 days/week through October 31,2004	Weekdays On-Peak/Emergency	May 1 – Oct 31& Nov1-April 30	Weekdays through Oct 31, 2003
Eligible participant	C&I Customers	C&I Customers	C&I Customers	C&I Customers
Eligible load	>50 kW	>100 kW	>100 kW	>100 kW
Call criteria	Times of risk or reduced reliability	Power shortages or emergencies declared by NYISO	Follows terms of NYISO Installed Capacity Procedures for Special Case Resources	Local power shortages or emergencies declared by ConEd
Response period	30 minutes	Approximately 2 hours	2 hours	Minimum of 30 minutes
Respondent option	Optional	Voluntary	Mandatory, if the customer fails to comply will be charged a penalty equal to the NYISO's deficiency price	Voluntary
Duration	Minimum of 4 hours	Varies - Customers are paid for a minimum of 4 hours if they curtail for the entire duration of the declared event	Varies	Minimum of 4 hours
Compensation	Paid higher of $.50 for each kWh curtailed or the real-time LBMP-retail rate whichever is greater	The greater of $0.45 per kWh curtailed or 90% of LBMP - Different rates if event lasts less than 4 hours	Paid Capacity Payment Rate (capacity amount commited to curtail) and Service Curtailmen(Based upon LBMP adjusted for losses or the amount specified on the application not to exceed $0.50/kWh)	The greater of $0.50 per kWh curtailed or the LBMP less the retail rate - Different rates if event lasts less than 4 hours
Baseline criteria	Customer can choose different criteria, default is NYISO cirteria	Typical Demand calculated according to NYISO methodology (5 highest of 10 prior days)	Average maximum monthly one=hour integrated demand occuring in the season (periods defined above)	Typical Demand calculated according to NYISO methodology (5 highest of 10 prior days)
Performance Measure	?	Baseline difference	?	Baseline difference
Payment channel	Billing Credits or check on a quarterly basis	ConEd -> Customer	Billing Credits or check on a quarterly basis	ConEd -> Customer
Metering method	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line
Notification method	Must appoint authorized and alternate representatives	Phone, pager, e-mail, or fax	None specified	Phone, pager, e-mail, or fax
Software requirement	Yes-Provided at no charge by ConEd	None specified	None specified	None specified
Program fees	$2,500 credit avaliable for installation of interval meters	None specified	Customer responsible for installation of meters	None specified
Year Program Began				
Customer Accounts Enrolled - 2004				
MW Enrolled - 2004				
% of Enrolled MW Shed During Events				
Event Impacts Met Expectations?				
Strengths of Program				
Weaknesses of Program				
What Would Do Differently If Starting Over				
Nuances Not Understood by Others				
Key Lessons Learned				
Predessor Program				x

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Dominion Virginia Power Economic Load Curtailment Program	Dominion Virginia Power Real Time Program	Duquesne Light Company Energy Exchange	Entergy Experimental Energy Reduction Program (EER)
Period	May 1 - Sep 30 & Oct 1 - April 30	Weekdays - All Year	Weekday On-Peak	Weekdays-All Year
Eligible participant	Non-residential customers	C&I Customers	C&I Customers	C & I Customers
Eligible load	>1 MW and able to curtail at least 500 kWh	>5 MW	>500 kW	>150 kW
Call criteria	Whenever company elects	N/A - Real Time Pricing	Wholesale prices exceed a pre-determined strike price	Constrained Supply
Response period	1 hour	Each day, by 5:00 PM, hourly energy prices will be posted for the next day During critical situations, customers must revert to CBL within 30 minutes of request or face penalties.	Customers are given a password to access the website and view price offers. They must respond within a minimum of 4 hours but usually have 24 hours to decide	Prices posted day-ahead by 8 AM, customer must commit by 11AM day ahead
Respondent option	Customer has the option to bid a curtailment; however, if a customer's bid is accepted it must curtail or is subject to penalties	Voluntary	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties
Duration	Varies	N/A - Real Time Pricing	Varies	2-6PM; Must participate for all 4 hours
Compensation	Company-specified rate per kWh reduction	Customers are credited or charged, based upon market price, for usage below or above CBL	Company-specified rate per kWh curtailed	Curtailable Billing Energy* Bidding Price
Baseline criteria	Historical summer and winter reference profile	Typical Demand	Typical Demand	Average hourly interval demand
Performance Measure	Baseline difference	Baseline difference	Baseline difference	Baseline difference
Payment channel	DVP -> Customer	DVP -> Customer	DLP -> Customer	Entergy->Customer
Metering method	Interval Meter	Interval meter with phone line or communications capability	Interval Meter	Interval Meter
Notification method	Fax or other mutually agreed upon form of communication	e-mail	e-mail	Email, phone call, or fax
Software requirement	None specified	IBM PC with modem & software package provided by DVP	Software package from the Demand Exchange	Not Specified
Program fees	None specified	None specified	None specified	None Specified
Year Program Began				
Customer Accounts Enrolled - 2004				
MW Enrolled - 2004				
% of Enrolled MW Shed During Events				
Event Impacts Met Expectations?				
Strengths of Program				
Weaknesses of Program				
What Would Do Differently If Starting Over				
Nuances Not Understood by Others				
Key Lessons Learned				
Predessor Program	x	x		

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Entergy Market Value Call Option Service (MVCO)	Entergy Market Valued Energy Option (MVEO)	First Energy Voluntary Power Curtailment Program	First Energy Experimental Real Time Pricing Program
Period	May 1 – September 30 Sunday – Saturday	May 1 – Septmeber 30 Monday – Friday	Weekdays - All Year	All Year – All Days through December 31, 2005
Eligible participant	C & I Customers	C&I Customers	C&I Customers	Large Commercial Customers
Eligible load	Not specified, Enetergy customer submits curtailable amount with application	Not specified, Enetergy customer submits curtailable amount with application	>1 MW	Max 500 MW of demand
Call criteria	High demand &/or market prices	High demand &/or market prices	High demand &/or market prices	N/A - Real Time Pricing
Response period	Day Ahead and Same Day	Submitted by Customer in enabling Contract submitted to Entergy	Customers are given a password to access the website and view price offers - Can participate on an hourly or day-ahead basis	Next Day Prices posted at 1PM
Respondent option	Mandatory	Submitted by Customer in enabling Contract submitted to Entergy	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties	Voluntary
Duration	12:00 noon to 8PM Sun-Sat May June, September – Two events /month July and August – Five per month	12:00 noon to 8PM Monday-Friday	Varies - Customer must bid at least 4 successive one-hour periods	N/A - Real Time Pricing
Compensation	May June September - $50/MWh July August - $100/MWh	Submitted by Customer in enabling Contract submitted to Entergy	70% of the wholesale electricity price	Access Charge, Energy Charge (RTP component) and Service Charge
Baseline criteria	Typical Demand	Typical Demand	Typical Demand	Historical usage/may be adjusted if too much variance
Performance Measure	Baseline difference	Baseline difference	Baseline difference	?
Payment channel	Entergy->Customer	Entergy->Customer	FE -> Customer	FE-> Customer
Metering method	Interval Meter	Interval Meter	Interval meter with phone line	Interval Meter
Notification method	Email, phone call, or fax	Submitted by Customer in enabling Contract submitted to Entergy	e-mail, pager, phone	Internet
Software requirement	Email, phone call, or fax	None specified	Internet	Internet
Program fees	$500/month	$500/month	None specified	$150.00 per billing period
Year Program Began				
Customer Accounts Enrolled - 2004				
MW Enrolled - 2004				
% of Enrolled MW Shed During Events				
Event Impacts Met Expectations?				
Strengths of Program				
Weaknesses of Program				
What Would Do Differently If Starting Over				
Nuances Not Understood by Others				
Key Lessons Learned				
Predessor Program				

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Georgia Power Daily Energy Credit Program	Georgia Power Real Time Pricing Program	Idaho Power Energy Exchange Program	ISO-NE Demand Response Program (Class 1)
Period	Weekdays May - Sept	Weekdays - All Year	Weekdays - All Year	May 1, 2002 - May 31, 2003 7 am – 6 pm wkdys
Eligible participant	C&I Customers	C&I Customers	C&I and Large Irrigation Customers	NEPOOL participant or an end user that uses an active NEPOOL participant as the Enrolling Participant
Eligible load	>500 kW	>250 kW - Day-Ahead Option >5 MW - Hour-Ahead Option	>1 MW	100 kW - 5 MW Aggregation of load by the enrolling participant is allowed
Call criteria	High demand &/or market prices	N/A - Real Time Pricing	High demand &/or market prices	10 Minute Operating Reserve Deficiency
Response period	Minimum of 1 hour - DEC price is posted by 11 AM; customers have until 12 noon to accept the price	Each day, by 4:00 PM, hourly energy prices will be posted for the next day For hourly option, prices are updated 60 minutes before becoming effective	Same-Day, Day-Ahead, and 2-Day-Ahead options	30 minutes
Respondent option	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties	Voluntary	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties	Mandatory - penalties (loss of TMOR payment and capability rating until next successful curtailment event) exist for non-compliance
Duration	If customer accepts the price, they agree to curtail from 2 pm - 7 pm	N/A - Real Time Pricing	Minimum of 2 consecutive hours per event Can be more than 1 event per day	Normally less than two hours but can be longer during system emergencies
Compensation	Company-specified rate per kWh curtailed - Daily Energy Credit price	Hourly prices are determined each day based on projections of the hourly running cost of incremental generation, provisions for losses, projections of hourly transmission costs and outage costs for each day (when applicable), and a 3 mill/kWh recovery factor	Company-specified bid price	Customers are paid an ongoing administrative fee based on the Thirty-Minute Operating Reserve (TMOR) clearing price, in addition to receiving Installed Capability (ICAP) credit that can be valued in the ICAP market. Class 1 Customers are also paid for an actual interruption at the higher of the Energy Clearing Price (ECP) adjusted by a Congestion Cost Multiplier (CCM) or $100 per MW
Baseline criteria	Typical Demand based upon one year's worth of hourly firm load data or monthly billing determinant data	Typical Demand based upon one year's worth of hourly firm load data or monthly billing determinant data	Typical Demand	10 prior wkdys with adjustments based upon actual usage during the 2 hours preceding the interruption
Performance Measure	Baseline difference - Customer must curtail to mutually agreed upon Firm Demand Level	Baseline difference	Baseline difference	Baseline difference
Payment channel	GP -> Customer via monthly bill credit	GP -> Customer via monthly bill credit/charge	IP -> Customer account within 45 days	ISO-NE -> NEPOOL/Enrolling Participant via monthly bill credit
Metering method	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line	Interval meter & IBCS
Notification method	Website, email, or pager	Mutually-agreed upon method	Website, e-mail, pager, phone, or fax	Internet based communication system (IBCS) supplied by RETX
Software requirement	Internet	None specified	Internet	IBCS supplied by RETX
Program fees	$100 per month May - Sep	For day-ahead program, $155 per month for customers >1 MW & $175 per month for customers < 1 MW For hour-ahead program, $850 per month	None specified	First 1000 customers are reimbursed 100% of hardware costs - Subsequent customers pay for hardware
Year Program Began				2001
Customer Accounts Enrolled - 2004				15 (Class I + II total)
MW Enrolled - 2004				27 MW (Class I + II total)
% of Enrolled MW Shed During Events				0.7
Event Impacts Met Expectations?				Yes
Strengths of Program				Pilot
Weaknesses of Program				Pilot
What Would Do Differently If Starting Over				These programs are the start.
Nuances Not Understood by Others				
Key Lessons Learned				Integrate with energy efficiency, do audits for customers to see DR opportunities. Present all information in a way that shows customers what's in it for them. Direct communication with customer to help them understand the business case for them. Ensure accurate and timely meter data. Ensure reliable ways of notifying customers.
Predessor Program			x	x

Exhibit I.3
Non-California DR Programs

Program Sponsor:	ISO-NE Price Response Program (Class 2)	ISO-NE Day Ahead Demand Response	ISO-NE Real Time Demand Response	ISO-NE Real Time Price Response
Period	May 1, 2002 - May 31, 2003 7 am – 11 pm wkdys	Weekdays from 0700 - 1800 through 2/28/2006	Weekdays from 0700 - 1800 through 2/28/2006	Weekdays from 0700 - 1800 through 2/28/2006
Eligible participant	NEPOOL participant or an end user that uses an active NEPOOL participant as the Enrolling Participant	Enrolling Participants (NEPOOL Participants and DRPs)	Enrolling Participants (NEPOOL Participants and DRPs)	Enrolling Participants (NEPOOL Participants and DRPs)
Eligible load	100 kW - 5 MW Aggregation of load by the enrolling participant is allowed	> 1 MW (aggregation is allowed)	100 kW - 5 MW (aggregation is allowed)	100 kW - 5 MW (aggregation is allowed)
Call criteria	Hourly Energy Clearing Price >= $100/MWh	Respond to ISO Control Room Request	Respond to ISO Control Room Request	The forecast hourly Zonal Price is >= $100/MWh
Response period	Variable	Bids submitted on a day-ahead basis	30 minute or 2 hours notice	Utilize price signals sent by ISO-NE
Respondent option	Voluntary	Mandatory if bid is accepted. Capability ratings reductions occur if performance does not meet bid.	Mandatory. Capability ratings reductions occur if performance does not meet bid.	Voluntary
Duration	Variable	None specified	2 hour minimum guaranteed payment period	Varies
Compensation	The hourly Energy Clearing Price adjusted by the Congestion Cost Management Multiplier is paid for the duration of the interruption	The applicable Day-Ahead Zonal Price with deviations charged or credited at the appropriate Real-Time Zonal Price. May participate in the Real-Time Price Response Program if their offer did not clear in the Day-Ahead Energy Market. Also eligible to qualify as an ICAP Resource.	The higher of the Real Time Zonal Price or $500/MWh (30 minute) or $350/MWh (2 hour). Also eligible to qualify as an ICAP Resource.	The higher of the applicable Real-Time Zonal Price for interrupted consumption (measured against the base line) or a guaranteed minimum payment of $100/MWh.
Baseline criteria	10 prior wkdys with adjustments based upon actual usage during the 2 hours preceding the interruption	Formula using the weighted average of the previous 5 non-event weekday's CB and the meter data for the present program day	Formula using the weighted average of the previous 5 non-event weekday's CB and the meter data for the present program day	Formula using the weighted average of the previous 5 non-event weekday's CB and the meter data for the present program day
Performance Measure	Baseline difference	?	?	?
Payment channel	ISO-NE -> NEPOOL/Enrolling Participant via monthly bill credit	ISO-NE -> Enrolling Participant -> end-use customer (if necessary)	ISO-NE -> Enrolling Participant -> end-use customer (if necessary)	ISO-NE -> Enrolling Participant -> end-use customer (if necessary)
Metering method	Interval meter, phone line, PC	5 minute interval meters	5 minute interval meters	Hourly meter
Notification method	IBCS supplied by RETX or Low Tech Option (Website & email)	Day-ahead market	IBCS	IBCS or low-tech option
Software requirement	Optional IBCS supplied by RETX	IBCS	IBCS	IBCS or meter
Program fees	First 1000 customers are reimbursed 50% of hardware costs - Subsequent customers pay for hardware	Enrolling Participants in the LRP selecting the IBCS protocol will be subject to fees that will be negotiated directly between the Enrolling Participant and their IBCS Provider; however, ISO-NE will offset costs for intial participants	Enrolling Participants in the LRP selecting the IBCS protocol will be subject to fees that will be negotiated directly between the Enrolling Participant and their IBCS Provider; however, ISO-NE will offset costs for intial participants	Enrolling Participants in the LRP selecting the IBCS protocol will be subject to fees that will be negotiated directly between the Enrolling Participant and their IBCS Provider; however, ISO-NE will offset costs for intial participants
Year Program Began	2001	2003	2003	2003
Customer Accounts Enrolled - 2004	15 (Class I + II total)			
MW Enrolled - 2004	27 MW (Class I + II total)	400 MW (all 4 programs total)	400 MW (all 4 programs total)	400 MW (all 4 programs total)
% of Enrolled MW Shed During Events	0.7	0.1	0.1	0.1
Event Impacts Met Expectations?	Yes	Given low wholesale price, yes	Given low wholesale price, yes	Given low wholesale price, yes
Strengths of Program	Pilot	Flexibility. No penalty. Good marketing approach - marketing message in simple business terms. Customers like the money and load information.	Flexibility. No penalty. Good marketing approach - marketing message in simple business terms. Customers like the money and load information.	Flexibility. No penalty. Good marketing approach - marketing message in simple business terms. Customers like the money and load information.
Weaknesses of Program	Pilot	Need a way to maximize the value DR can provide to the market - no energy or reserve margin value/compensation. One capacity market.	Need a way to maximize the value DR can provide to the market - no energy or reserve margin value/compensation. One capacity market.	Need a way to maximize the value DR can provide to the market - no energy or reserve margin value/compensation. One capacity market.
What Would Do Differently If Starting Over	These programs are the start.	Raise wholesale prices and create appropriate market structures (e.g., including payment in program design)	Raise wholesale prices and create appropriate market structures (e.g., including payment in program design)	Raise wholesale prices and create appropriate market structures (e.g., including payment in program design)
Nuances Not Understood by Others		Integrating energy efficiency is key - makes customers more likely to participate, adds to overall value proposition. Technology solutions depend on the value proposition - be wary of technology in search of a solution. Customers need to see that understanding their load shape is and being able to do something will enable them to get a better price. The day will come when subsidies go away and customers will be shocked by what competition really means.	Integrating energy efficiency is key - makes customers more likely to participate, adds to overall value proposition. Technology solutions depend on the value proposition - be wary of technology in search of a solution. Customers need to see that understanding their load shape is and being able to do something will enable them to get a better price. The day will come when subsidies go away and customers will be shocked by what competition really means.	Integrating energy efficiency is key - makes customers more likely to participate, adds to overall value proposition. Technology solutions depend on the value proposition - be wary of technology in search of a solution. Customers need to see that understanding their load shape is and being able to do something will enable them to get a better price. The day will come when subsidies go away and customers will be shocked by what competition really means.
Key Lessons Learned	Integrate with energy efficiency, do audits for customers to see DR opportunities. Present all information in a way that shows customers what's in it for them. Direct communication with customer to help them understand the business case for them. Ensure accurate and timely meter data. Ensure reliable ways of notifying customers.	Integrate with energy efficiency, do audits for customers to see DR opportunities. Present all information in a way that shows customers what's in it for them. Direct communication with customer to help them understand the business case for them. Ensure accurate and timely meter data. Ensure reliable ways of notifying customers.	Integrate with energy efficiency, do audits for customers to see DR opportunities. Present all information in a way that shows customers what's in it for them. Direct communication with customer to help them understand the business case for them. Ensure accurate and timely meter data. Ensure reliable ways of notifying customers.	Integrate with energy efficiency, do audits for customers to see DR opportunities. Present all information in a way that shows customers what's in it for them. Direct communication with customer to help them understand the business case for them. Ensure accurate and timely meter data. Ensure reliable ways of notifying customers.
Predessor Program	x			

Exhibit I.3
Non-California DR Programs

Program Sponsor:	ISO-NE Real Time Profiled Response	Kansas City Power & Light Peak Load Curtailment Program	Kansas City Power & Light Real Time Pricing Program	Kansas City Power & Light Voluntary Load Reduction Program
Period	Weekdays from 0700 - 1800 through 2/28/2006	Weekdays July 1- Sep 1 12 noon - 10 PM	Weekdays - All Year	Weekdays May 1 – Sep 30 12 noon - 10 PM
Eligible participant	Enrolling Participants (NEPOOL Participants and DRPs) aggregate non-interval metered customers	C&I Customers	C&I Customers	C&I Customers
Eligible load	100 kW - 5 MW (aggregation is allowed)	>200 kW	>500 kW	>100 kW
Call criteria	Respond to ISO Control Room Request	High demand &/or market prices	N/A - Real Time Pricing	High demand &/or market prices
Response period	On demand and within 2 hours	Minimum of 4 hours Between noon and 10 pm Monday-Friday	Each day, by 4:00 PM, hourly energy prices will be posted for the next day	Maximum of 2 hours
Respondent option	Mandatory. Capability ratings reductions occur if performance does not meet bid.	Mandatory	Voluntary	Voluntary
Duration	2 hour minimum guaranteed payment period	Maximum of 25 events, 8 hours per day, and 120 hours total	N/A - Real Time Pricing	Varies
Compensation	Enrolling Participant will receive the higher of the applicable Real-Time Zonal Price or a minimum payment of $100/MWh for the actual real-time statistically determined response quantity.	Fixed monthly credits of $10 per curtailable kW	Company-specified rate per kWh curtailed	Credits are earned when customers reduces load below 90% of Average Monthly Peak. Credits are based upon company-specified credit value
Baseline criteria	No customer baseline necessary since response is determined statistically	Typical Demand	Typical Demand	Typical Demand
Performance Measure	?	Baseline difference	Baseline difference	Baseline difference
Payment channel	ISO-NE -> Enrolling Participant -> end-use customer	KCPL -> Customer via guaranteed monthly bill credits July 1 – Sep 1	KCPL -> Customer	KCPL -> Customer via guaranteed monthly bill credits May - Sep
Metering method	Sufficient research meters or equivalent technology shall be used to provide statistical confidence regarding the amount of interruption achieved	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line
Notification method	IBCS	Fax, e-mail	EnerLink analysis tool presents prices and allows customers to see how their decisions affect their bills	Fax, e-mail
Software requirement	IBCS	None specified	EnerLink Web-based tool	None specified
Program fees	Enrolling Participants in the LRP selecting the IBCS protocol will be subject to fees that will be negotiated directly between the Enrolling Participant and their IBCS Provider; however, ISO-NE will offset costs for intial participants	None specified	None specified	None specified – all metering equipment installed free of charge
Year Program Began	2003	1993		1993
Customer Accounts Enrolled - 2004		9		0
MW Enrolled - 2004	400 MW (all 4 programs total)	13 MW (down from 32 MW in 2003) - ~1/2 use DG		0
% of Enrolled MW Shed During Events	0.1	0.92		NA - no customers
Event Impacts Met Expectations?	Given low wholesale price, yes	Yes		NA - no events
Strengths of Program	Flexibility. No penalty. Good marketing approach - marketing message in simple business terms. Customers like the money and load information.	Highly reliable. Low cost. Use for both capacity and economic dispatch. Internet site to track usage. Envoy communications/notification system.		None cited.
Weaknesses of Program	Need a way to maximize the value DR can provide to the market - no energy or reserve margin value/compensation. One capacity market.	Low strike price on incremental retail price of 4.5 cents/kWh. Unlimited consecutive days allowed to curtail.		Strike price too low, so customers not responding. Amount of work to recruit customers not worth the effort given the low strike price, so program not operated this year.
What Would Do Differently If Starting Over	Raise wholesale prices and create appropriate market structures (e.g., including payment in program design)	Will roll out redesigned program next year: capacity AND energy credits; energy credit set @ $0.36/kW/EVENT (vs. kWh - addresses spot mkt price spike effects); cap on consecutive days curtailment (3 days); buy-through option.		Focusing on redesigned PLC program.
Nuances Not Understood by Others	Integrating energy efficiency is key - makes customers more likely to participate, adds to overall value proposition. Technology solutions depend on the value proposition - be wary of technology in search of a solution. Customers need to see that understanding their load shape is and being able to do something will enable them to get a better price. The day will come when subsidies go away and customers will be shocked by what competition really means.	No explicit waiver process - case-by-case consideration. Not a lot of thought on how to evaluate program financially. Can't start and stop program like the spot market behaves. New program will have the administratively simple feature of $0.36/kW/event credit regardless of event length, so short curtailments have larger "unit" benefit to customers, plus moderates temptation of system ops to call events unless spot prices stay high for longer time.		None cited.
Key Lessons Learned	Integrate with energy efficiency, do audits for customers to see DR opportunities. Present all information in a way that shows customers what's in it for them. Direct communication with customer to help them understand the business case for them. Ensure accurate and timely meter data. Ensure reliable ways of notifying customers.	If abuse the program will wear out the product. Need to not curtail 5 days in a row, and reduce the number of events. Portfolio rationalizing to keep options simple for customers, utility.		None cited.
Predessor Program				

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Lincoln Electric System Load Purchase Program	Lincoln Electric Daily Curtailment	Lincoln Electric Seasonal Curtailment	Long Island Power Authority Peak Reduction Program
Period	Weekdays Jun - Sep	Any time, typically summer days between 7am and 10pm	Any time, typically summer weekdays between 2pm and 8pm	Weekdays Jun - Sep
Eligible participant	C&I Customers	C&I Customers	C&I Customers	C&I Customers
Eligible load	>100 kW	>100 kW	>100 kW	>50 kW
Call criteria	High demand &/or market prices	High demand &/or market prices	High demand &/or market prices	High demand &/or market prices
Response period	Minimum of 2 hours	Minimum 2 hours	Minimum 2 hours	Minimum of 4 hours
Respondent option	Voluntary - Payments are calculated on a performance basis, so customers that don't curtail forfeit payment	Voluntary on a day to day basis	Voluntary - anyone who fails to curtail forefits payment	LIPA and customer agree upon a contracted amount of load reduction. If the customer does not meet contracted amount, they are not fully compensated
Duration	Maximum of 20 events per season and 10 hours per day Minimum of 6 hours per event	No maximum amount of events, when event is scheduled, must me a minimum of six hours	Maximum of 20 events per summer season and no more than 10 hours a day (Minimum six hours)	4 hours (2 PM - 6 PM)
Compensation	For the seasonal option (a less popular daily option also exists), compensation is provided to customers who curtail during all events. In 2000, $20 per kW of load reduction and $0.12 per kWh reduced or generated during event	$0.15/kWh	$5 per kW of load reduction and $0.12/kWh for energy reduced or generated	$1.61 per kW per hour of load shed Customers will not be compensated for load shed in excess of contracted amount
Baseline criteria	Typical Demand	Typical Demand	Typical Demand	NYISO's customer baseline calculation from the EDRP
Performance Measure	Baseline difference	?	?	Baseline difference
Payment channel	LES -> Customer	LES -> Customer	LES -> Customer	LIPA -> Customer via bill credits
Metering method	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line
Notification method	Fax and phone	Fax and phone	Fax and phone	Telephone or other means available
Software requirement	None specified	None specified	None specified	None specified
Program fees	Participants are responsible for meter installation	Not specified	Hardware is free, installation is customer's responsibility	None specified
Year Program Began				
Customer Accounts Enrolled - 2004				
MW Enrolled - 2004				
% of Enrolled MW Shed During Events				
Event Impacts Met Expectations?				
Strengths of Program				
Weaknesses of Program				
What Would Do Differently If Starting Over				
Nuances Not Understood by Others				
Key Lessons Learned				
Predessor Program	x			x

Exhibit I.3
Non-California DR Programs

Program Sponsor:	NYISO Day-Ahead Demand Response Program	NYISO Emergency Demand Response Program	NYISO ICAP/SCR Program	New York Power Authority Peak Load Management Program
Period	Weekdays, May 1 - Oct 31 through 2005	Weekdays, May 1 - Oct 31 through 2005	Weekdays, May 1 - Oct 31 through 2005	Weekdays Jun - Sep
Eligible participant	LSE, Direct Customer, & Aggregators (DRPs - Demand Reduction Providers)	LSE, Direct Customer, & Aggregators (CSPs - Curtailment Service Providers)	LSE, Direct Customer, & Aggregators (RIPs - Responsible Interface Providers)	C&I Customers
Eligible load	>1 MW per NYISO Zone (may aggregate within zones)	>100 kW per NYISO Zone (may aggregate within zones)	>100 kW per NYISO Zone (may aggregate within zones)	No minimum load reduction commitment, but the amount must be measurable (generally 100 kW)
Call criteria	Curtailment opportunities based on customer bids not system conditions.	Operating Reserves Deficiency or other emergency state	Operating Reserves Deficiency or other emergency state	High demand &/or market prices
Response period	Notified by 11:00 AM on a day-ahead basis if bid is accepted.	2 hours	21 hours ahead with 2 hour in-day notification during Operating Reserve deficiency	NYPA provides participants with a day-ahead alert and then notifies them again at least 2 hours before the event begins
Respondent option	Mandatory Response – Penalties Assessed for Non-Compliance. Penalized for buy-through at Day-Ahead or Real-Time marginal price, whichever is greater.	Voluntary - No penalties for non-performance	Mandatory Response – Resources Derated for Non-Compliance	Each participant is allowed one waiver per season Non-compliance results in no incentive penalty
Duration	As bid	Four hour minimum call	Four hour minimum call	Minimum of 2 hours & maximum of 6 hours between 11 AM and 7 PM NYPA can call up to 15 events or a maximum of 90 hours of requested curtailment
Compensation	Greater of LBMP or bid for actual interruption. Minimum bid of $50/MWh.	Greater of Real Time Locational Based Marginal Price (LBMP) or $500/MWh of load reduction Participants will be paid for at least 4 hours per event (at least 2 hours as specified above and the remaining non-EDRP hours at LBMP)	Greater of real-time market price or Strike Price (maximum $500/MWh), whichever is greater & guaranteed 4 hour minimum. May set real time market price under scarcity pricing rules.	$40 per kW per season
Baseline criteria	5 highest of 10 prior weekdays Optional weather-sensitive CBL shifts CBL upwards or downwards ± 20% so as to line up CBL and actual load in hours just prior to event.	5 highest of 10 prior weekdays Optional weather-sensitive CBL shifts CBL upwards or downwards ± 20% so as to line up CBL and actual load in hours just prior to event.	5 highest of 10 prior weekdays Optional weather-sensitive CBL shifts CBL upwards or downwards ± 20% so as to line up CBL and actual load in hours just prior to event.	NYISO's customer baseline calculation from the EDRP
Performance Measure	Baseline difference	Baseline difference	?	Baseline difference
Payment channel	NYISO -> LSE/DRP -> end-use customer	NYISO -> LSE/CSP -> end-use customer	NYISO -> LSE/RIP -> end-use customer	NYPA -> Customer via bill credits
Metering method	Hourly interval meter	Hourly interval meter	Hourly interval meter	Interval meter with phone line
Notification method	Day Ahead notification over internet	Minimum 2 hour prior notice via the internet, email, phone, pager notification	Minimum 2 hour prior notice via the internet, email, phone, pager notification	Telephone or other means available
Software requirement	Internet to ISO	Internet	Internet	None specified
Program fees	None specified	None specified	None specified	None specified
Year Program Began	2001			
Customer Accounts Enrolled - 2004	27			
MW Enrolled - 2004	414 MW			
% of Enrolled MW Shed During Events	0.01			
Event Impacts Met Expectations?	Yes (hoped for more but low market price)			
Strengths of Program	Fully in place. Integrated into day-ahead market. Prices partly reflect bids - lots of bids could lower market price. Eliminated sunset. Eliminated penalties & make settlement same as generators.			
Weaknesses of Program	$50/MWh floor price is too low - increase to $75 being accepted. Free ridership issue. Used to have sunset & penalties. Software for bidding has 1 MW increment, which is too big.			
What Would Do Differently If Starting Over	LSE and customer get payments. Non-performance penalty dropped, 1 MW increment gone from bid software. Easy simulation tool. Easier bid preparation process.			
Nuances Not Understood by Others	Audit capability is critical (likes NYSERDA's support on providing audits). Minimize level of technology (KISS). Having program offered by ISO is important simplification. Amount of outreach - still trying to overcome constraints to doing that so all who could be interested are aware of the program.			
Key Lessons Learned	Ultimately, RTP is the way to go, but unpopular with customers. ISO has attracted curtailment service providers to turn them into program recruiters, too. KISS!			
Predessor Program				x

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Otter Tail Power Real Time Pricing Program	Otter Tail Power Released Energy Access Program	PacifiCorp Energy Exchange Program	PECO Voluntary Load Reduction Program
Period	Weekdays - All Year	Weekdays - All Year	Weekdays - All Year	Weekdays Jun - Sep
Eligible participant	C&I Customers	C&I Customers	C&I Customers	C&I Customers
Eligible load	>200 kW	>1 MW	>1 MW	>250 kW
Call criteria	N/A - Real Time Pricing	High demand &/or market prices	High demand &/or market prices	High demand &/or market prices
Response period	Each day, by 4:00 PM, hourly energy prices will be posted for the next day	Not specified	Specified by customer Varies with Minimum Hourly Credit Rate	Day-ahead - 3 PM prior day Day-of options - at least 1 hour's notice
Respondent option	Voluntary	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties and expulsion from program	Voluntary
Duration	N/A - Real Time Pricing	Varies	Curtailment events may last for 1 or more consecutive hours and their may be more than 1 event per day	Maximum of 6 hours
Compensation	Company-specified rate per kWh curtailed based upon hourly incremental generation costs, transmission costs, losses due to voltage level, hourly outage costs, and profit margin	Company-specified rate per MWh reduced or percentage of sale margin for each off-system energy sale	Company-specified Hourly Credit Rate per kWh curtailed	Day-ahead - 33% of the PJM LMP Day-of - 50% of the PJM LMP Fixed Price - $200 per MWh curtailed + $25 per MWh curtailed bonus for achieving 80% of reduction target
Baseline criteria	Typical Demand calculated from previous 12 month data	Typical Demand	Typical Demand calculated from previous 12 month data	Typical demand based upon previous similar 5-day average (adjusted for the average of the 3 actual hours before the event for Day-of participants) Variable Price – Based upon LMP day ahead -33%, day-of 50%
Performance Measure	Baseline difference	Baseline difference	Baseline difference	Baseline difference
Payment channel	OTP -> Customer via monthly bill	OTP -> Customer via monthly bill	PacifiCorp -> Customer within 45 days	PECO -> Customer via bill credits in November
Metering method	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line
Notification method	Not specified	e-mail	Website, e-mail, phone	E-mail, pager, phone, or fax
Software requirement	Not specified	Company-specified communications equipment	Software package from the Demand Exchange (Apogee Itneracitve's Demand Exchange DEMX)	None specified
Program fees	Customer is responsible for any meter upgrade costs	Customer is responsible for any meter upgrade costs	None specified	None specified
Year Program Began				
Customer Accounts Enrolled - 2004				
MW Enrolled - 2004				
% of Enrolled MW Shed During Events				
Event Impacts Met Expectations?				
Strengths of Program				
Weaknesses of Program				
What Would Do Differently If Starting Over				
Nuances Not Understood by Others				
Key Lessons Learned				
Predessor Program				

Exhibit I.3
Non-California DR Programs

Program Sponsor:	PECO Curtailment HT Rider	Pepco Curtailable Load Program	PJM Day-Ahead & Real Time Economic Load Response Program	PJM Emergency Load Response Program
Period	8am-8pm Weekdays	Weekdays June 1 – Sep 30 unless emergency conditions exist during other periods	Jun 1, 2002 - Dec 1, 2004	Weekdays - Jun 1, 2002 - Oct 31, 2004 - To be reviewed after each summer period
Eligible participant	C&I Customers on rider before Jan 1,1999	C&I and Governmental Customers	PJM Members (CSP or LSE)	PJM Members (CSP or LSE)
Eligible load	>1 MW	>50 kW	PJM members are required to participate	>100 kW - PJM members are required to participate
Call criteria	Any Prodcution, Transmission, or distirbution capacity limitations exist.	High demand &/or market prices	High LMP	Declaration of Maximum Emergency Generation and prior to the implementation of Active Load Management
Response period	1 hour	30 minutes	Day-Ahead and Real Time (at least 1 hour prior to event) Options	Minimum of 1 hour
Respondent option	Mandatory - $24.00 per kWh of excess energy penalties are associated with non-compliance	Voluntary, but the respondent can be dropped from the program for non-compliance	Real time is voluntary Day-Ahead non-performance is subject to penalties equal to the higher of day-ahead or real time LMP for the amount of the shortfall, plus any associated day-ahead operating reserve credits.	Voluntary
Duration	Total coccurances will not exceed 20 and total hours will not exceed 200 in a 12 month period.	Maximum of 6 hours on 15 separate weekdays unless emergency conditions exist	As bid	Two hour minimum call
Compensation	Monthly credit of $2.03 per kW	Average reduction achieved per period * company-specified credit	LMP less G&T Charges if LMP < $75/MWh otherwise real time LMP	Greater of Real Time Locational Marginal Price (LMP) or $500/MWh
Baseline criteria	Firm demand specified in the contract	Maximum 30 minute on-peak demand during previous summer	5 highest of 10 prior weekdays	5 highest of 10 prior weekdays
Performance Measure	?	Baseline difference	Baseline difference	Baseline difference
Payment channel	PECO Curtailment HT Rider	Pepco -> Customer via monthly bill credits	PJM -> PJM Member -> end-use customer	PJM -> PJM Member -> end-use customer
Metering method	Interval meter	Interval meter	Hourly interval meter	Hourly interval meter
Notification method	Not Specified	Warning board or phone	PJM Website and email	PJM Website and email
Software requirement	None specified	None specified	Internet	Internet
Program fees	None specified	None specified	None specified	None specified
Year Program Began		Early 1980s		
Customer Accounts Enrolled - 2004		195		
MW Enrolled - 2004		25 MW coincident with PJM peak (used to have 50-55 MW); 30-35 MW Pepco-coincident		
% of Enrolled MW Shed During Events		0.9		
Event Impacts Met Expectations?		Yes - steady-state program not marketed in 7-8 years, no customer "handholding" like used to do.		
Strengths of Program		Reconfigured program to be compatible with PJM pool and restructured market. Load data web site		
Weaknesses of Program		Capacity surplus has meant no program operations. Complicated capacity credit calculations because of PJM pool being the basis for coincident impact & controlling the economics and parameters. Used to have penalties but got rid of those in 2002.		
What Would Do Differently If Starting Over		Already changed the program when restructuring occurred, to orient to PJM pool capacity and pricing rules. Changed how customer credits calculated. Can receive either capacity or energy credits.		
Nuances Not Understood by Others		23% PJM reserve margin (vs. 15% minimum) means low wholesale prices and so no program operations. Customers are forgetting about the program and how to work it (no assigned account reps anymore, though still have annual breakfast meetings). Program is deregulated but run in regulated utility service areas, so get cost recovery and PJM market credites, but program barely economic.		
Key Lessons Learned		Planning to discontinue after 2004. Retail switching is changing customers to alternate suppliers, which complicates the program situation. With 60% increase in energy cost, customers are focused on finding low-cost commodity providers, but not looking for DR solutions.		
Predessor Program				

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Portland General Electric Demand Buy Back Program	PPL Demand Side Initiative Rider	Sacramento Municipal Utility District PowerDirect	Sacramento Municipal Utility District PowerNet
Period	Weekdays - All Year	Weekdays - All Year	24 hours a day, year-round	24 hours a day, year-round
Eligible participant	C&I Customers	C&I Customers	C&I Customers	C&I Customers
Eligible load	>250 kW	>1 MW	>100 kW	>75 kW
Call criteria	High demand &/or market prices	N/A - Real Time Pricing	High demand &/or market prices Customers specify predetermined weekly time period, price, and load reduction	High demand &/or market prices Customers specify predetermined weekly time period, price, and load reduction
Response period	12 hours to 2 days	Each day, by 5:00 PM, hourly energy prices will be posted for the next day	Prices are posted from 1 hour to 2 or more days prior to the curtailment event	Prices are posted from 1 hour to 2 or more days prior to the curtailment event
Respondent option	Voluntary; however, if the customer's bid is accepted, it must participate or be subject to penalties and expulsion from program	Voluntary	Voluntary, customer's pre-designated systems will be turned off automatically for the agreed upon time by SMUD via the Internet if customer chooses to participate	Voluntary; however, a penalty of 2X the bid price times the hours the curtailment fell below 80% will be assessed if curtailed load falls below 80% of pledged amount.
Duration	2 - 24 hours	N/A - Real Time Pricing	Minimum of 2 hours At least one weekday during Jun - Sep	Minimum of 2 hours At least one weekday during Jun - Sep
Compensation	$0.10 - $0.45 per kWh reduced depending on market prices If curtailment event is canceled but customer still curtails, customer receives small credits based upon the timing of the notification	Customer is exposed to the actual market price for electricity, so indirect compensation occurs if customer reduces or shifts loads	Pre-specified bid price generally at least 50% of SMUD's avoided costs or at least 50% of the market price of power - SMUD will pay up to 130% of pledged load reduction	Pre-specified bid price generally at least 50% of SMUD's avoided costs or at least 50% of the market price of power - SMUD will pay up to 130% of pledged load reduction
Baseline criteria	Typical demand based upon previous similar 14-day average	Typical demand based upon previous year's consumption data	Typical demand based upon previous similar 10-day average	Typical demand based upon previous similar 10-day average
Performance Measure	Baseline difference	Baseline difference	Baseline difference	Baseline difference
Payment channel	PGE -> Customer via check within 60 days	Net costs or savings are realized on monthly bills	SMUD -> Customer via bill credit	SMUD -> Customer via bill credit
Metering method	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line	Interval meter with phone line
Notification method	Interactive website	Interactive website (PPLLInk)	Internet and pager	Internet and pager
Software requirement	Internet	Internet	Web-based EMS provided by SMUD	Web-based EMS provided by SMUD
Program fees	None specified	$350 per month	None specified	None specified
Year Program Began	1999		2001	2001
Customer Accounts Enrolled - 2004	16 (had 26 in 2002)		20 (total both PowerDirect + PowerNet)	20 (total both PowerDirect + PowerNet)
MW Enrolled - 2004	30 MW (157 MW in 2001)		10 MW coincident of 2800 MW peak (total both PowerDirect + PowerNet)	10 MW coincident of 2800 MW peak (total both PowerDirect + PowerNet)
% of Enrolled MW Shed During Events	0.05		1	1
Event Impacts Met Expectations?	Yes		Yes, but never pushed after initial operations because realized wouldn't liekely call events.	Yes, but never pushed after initial operations because realized wouldn't liekely call events.
Strengths of Program	No major penalties (have to curtail 90% of commitment; if >1 day lower than 90% get a 5% penalty) and customers get paid for what they do curtail. Worked with individual customers - e.g., using past maintenance schedules to find DR opportunities. Paid credits with tangible check as recognition piece. Customers like the money.		Hard to tell because program hasn't been called.	Hard to tell because program hasn't been called.
Weaknesses of Program	Inactivity causing customers to forget how to manage their loads during curtailments (need testing).		Hard to tell because program hasn't been called.	Hard to tell because program hasn't been called.
What Would Do Differently If Starting Over	More customer contact, especially during "dry" periods. Use the energy product o inform about DR. Quarterly review with customers, provide spreadsheet & graphs to show what customers have done.		Come up with way to use for reliability/emergency purposes - can't do that with current design.	Come up with way to use for reliability/emergency purposes - can't do that with current design.
Nuances Not Understood by Others	Need to eductate customers about market pricing - they don't understand why the utility would curtail.		Have had state facilities approach SMUD for the program but in ISO emergency the program doesn't apply.	Have had state facilities approach SMUD for the program but in ISO emergency the program doesn't apply.
Key Lessons Learned	Be patient. Customers won't do DR on their own. Have dedicated employees to work the program.		Have curtailment contracts but don't make the program strictly a reliability program - continue voluntary approach but allow use in emergency situations, too.	Have curtailment contracts but don't make the program strictly a reliability program - continue voluntary approach but allow use in emergency situations, too.
Predessor Program			x	x

Exhibit I.3
Non-California DR Programs

Program Sponsor:	WE Energies Dollars for Power Program	WE Energies Experimental Energy Cooperative Curtailable	WE Energies General Primary Service – Curtailable	WE Energies Power Market Incentives Program
Period	Weekdays Jun - Sep	Weekdays - All Year	Weekdays - All Year	Weekdays - All Year
Eligible participant	C&I Customers	C&I Customers	C&I Customers	C&I Customers
Eligible load	>50 kW	>300 kW for customers w/ avg. monthly demand >3000kw or 100 kW or 10% of montly load for customers with demand<3000kw	>500 kW	>500 kW The Pool option allows >100 kW customers to aggregate their loads to at least 500 kW
Call criteria	Wholesale prices exceed pre-established bid prices	High demand &/or market prices	High demand &/or market prices	Wholesale prices exceed pre-established bid prices
Response period	Customers will be given as much advance notice as possible	One hour	One hour	Day-ahead and day-of options
Respondent option	Voluntary	Mandatory – Inability to curtail will result in a per kw penalty.	Mandatory – Inability to curtail will result in a per kw penalty.	Mandatory - If a participant does not meet its load reduction commitment, it will be responsible for the actual cost of replacement power
Duration	WE will set the start and end times for each event. Customers can participate in all or only a portion of each event.	Not specified	Varies, max 300 hours in any calendar year. Curtailment periods must be less than 8 hours between 8am and 10pm	Varies
Compensation	Pre-established Energy Credit Prices of $0.40, $0.80, or $1.25 per kWh curtailed	$2.00 per kW for all curtailable load during a billing period up to and $0.3 per kW of actual load reduction		Per kWh curtailed offer prices based upon hourly regional market prices
Baseline criteria	Typical Demand	Typical Demand	Customer bids the curtailable demand avaliable when contract is submitted	Typical Demand based upon a reference load shape adjusted for actual energy use in the 2 hours prior to PMI implementation
Performance Measure	Baseline Difference	?	?	Baseline Difference
Payment channel	WE -> Customer via monthly bill credits	WE -> Customer	WE -> Customer	WE -> Customer via monthly bill credits
Metering method	Interval meter	Interval Meter capable of 15 minute increments	Not Specified	Interval meter with phone line
Notification method	Pager	Not specified	Not Specified	PMI Website with pager/e-mail "tickler"
Software requirement	None specified	Not specified	Not Specified	Internet
Program fees	None specified	Not specified	Not Specified	None specified for single customers - $160 per month per pool
Year Program Began	1999	1999	1980s	1999
Customer Accounts Enrolled - 2004				
MW Enrolled - 2004				
% of Enrolled MW Shed During Events	0.25	0.25	0.25	0.25
Event Impacts Met Expectations?	Yes - given economics of the price	Yes - given economics of the price	Yes - given economics of the price	Yes - given economics of the price
Strengths of Program	Real financial reward based on market prices. Flexible. Voluntary. Sneak preview of deregulated market (but that's still a long way off in WI).	Real financial reward based on market prices. Flexible. Voluntary. Sneak preview of deregulated market (but that's still a long way off in WI).	Real financial reward based on market prices. Flexible. Voluntary. Sneak preview of deregulated market (but that's still a long way off in WI).	Real financial reward based on market prices. Flexible. Voluntary. Sneak preview of deregulated market (but that's still a long way off in WI).
Weaknesses of Program	Marginal economics given wholesale prices.	Marginal economics given wholesale prices.	Marginal economics given wholesale prices.	Marginal economics given wholesale prices.
What Would Do Differently If Starting Over	Implement a simulation tool to help customers figure out how to participate.	Implement a simulation tool to help customers figure out how to participate.	Implement a simulation tool to help customers figure out how to participate.	Implement a simulation tool to help customers figure out how to participate.
Nuances Not Understood by Others	Nothing cited.	Nothing cited.	Nothing cited.	Nothing cited.
Key Lessons Learned	Don't expect a lot of impact unless prices become extremely volatile.	Don't expect a lot of impact unless prices become extremely volatile.	Don't expect a lot of impact unless prices become extremely volatile.	Don't expect a lot of impact unless prices become extremely volatile.
Predessor Program				

Exhibit I.3
Non-California DR Programs

Program Sponsor:	Xcel Energy Peak Control (MN, ND, SD, WI, MI)	Xcel Energy Experimental Industrial Interruptible Rate Rider (TX)	Xcel Energy Transmission, Primary, Secondary Interruptible Rate (CO)
Period	Weekdays - All Year	Weekdays - All Year	Weekdays - All Year
Eligible participant	C&I Customers	C&I Customers	C&I Customers
Eligible load	>50 kW	>=1000 kW	>=500 kW
Call criteria	Forecasted load above MAPP Level.	Needed for System Relief	Needed for System Relief
Response period	Endeavor to provide 1 hour notice. 1 hour notice required in WI.	No Notice Option and 2 hour notice Option	no-notice and 30-minute notice options
Respondent option	Response is mandatory; Penalties: $10/kW Tier 1, $8/kW Tier 2	Response is mandatory, Penalties vary according to 1st, 2nd or 3rd violation. Basic penalty is 150% of the difference between the demand charge per kW on interruptible less firm demand charge times load not interrupted.	Response is mandatory; 1st occurrence Penalty $4/kW, then various depending on options (# events & notice level).
Duration	Tier 1: 150 hrs/yr max; Tier 2: 80 hrs/yr max plus odd/even day split to avoid consecutive days of curtailment. No cap on hrs/event except as annual cap applies. System emergencies - no hr cap	200 hr/yr cap; events called in rotational 25 MW blocks or groups.	As long as system requires relief. Tariff allows for maximum of 10, 20 or unlimited interruption days per year. Interruption day is 24 hours.
Compensation	Discounts vary by Tier and Performance Factor: $ 2.18 min to $6.27/ kW mo. max. Applied yr-round	Discounts vary according to service voltage and notice options. Range from $1.42 to $5.47/kW mo.	Discounts vary according to options (30 minute notice, No notice and number of interruptions per year) selected. Range from $.73 to $3.88/ kW mo.
Baseline criteria	Pre-determined firm service level, based on average of 3 highest July & 3 highest August days (1-7 PM)	No performance factors	No performance factors
Performance Measure	Baseline difference plus performance factor for impact coincidence based on customer's annual billing peak (low PFs get smaller discounts)	Baseline Difference	Baseline Difference
Payment channel	Participants receive reduced billing demand.	Participants receive reduce billing demand.	Participants receive reduced billing demand plus $1.61/ kW of interrupted demand per interruption for first 10 interruptions per yr.
Metering method	Interval meter	Interval meter	Interval meter
Notification method	Utilize Envoy WorldWide communication system which utilizes phone, fax, email, pager and cell technology to notify customers of events.	Utility based paging system used to communicate interruption commands to digital control units located at customer meter site.	RTU switch employing two way radio communication.
Software requirement	None specified	None	None
Program fees	Service and Facility Charge	Service and Facility Charge	Service and Facility Charge.
Year Program Began	Early 1980s	1996	1996
Customer Accounts Enrolled - 2004	2700	56	75
MW Enrolled - 2004	530 MW coincident	350 MW contracted (noncoincident)	145 contracted (noncoincident)
% of Enrolled MW Shed During Events	0.6	30-60%	Varies
Event Impacts Met Expectations?	Yes	Yes	Yes
Strengths of Program	New communications system (Envoy) has reduced notification from 3 hrs to <1 hr. Good discounts - options offered. Waiver process if XE was cause of underperformance. Customer breakfast meetings, time spent with customers. Tiered system to avoid consecu	Communications system. Good discounts. Penalties are the lowest of XE rates. Annual control period provides effective impact test.	2-way metering so know how much load impact is occurring. Good discounts.
Weaknesses of Program	Free riders (especially schools and others with peaks not in summer). Customers don't like the penalty levels. Customers with generators want longer control periods.	Penalties. Length of control. Customers with generators want longer control periods. Incentives are the lowest of the XE rates.	Penalties. Length of control. Customers with generators want longer control periods. Communications system requires land phone lines in mountainous areas.
What Would Do Differently If Starting Over	Split into smaller groups (two tiers still imposes more frequent events than needed sometimes). Geographic grouping to address distribution system issues.	Nothing cited.	Nothing cited.
Nuances Not Understood by Others	Nothing cited.	Nothing cited.	Nothing cited.
Key Lessons Learned	Figure out free riders and how to minimize their effect.	Figure out free riders and how to minimize their effect. Do market research and load research to know impact and how obtained. Watch out for special interest groups who want to make the program a way to subsidize certain interests.	Figure out free riders and how to minimize their effect.
Predessor Program			

APPENDIX J
SUB-METERING TASK: OVERVIEW OF WORK-I-N-PROGRESS

APPENDIX J
SUB-METERING TASK: OVERVIEW OF WORK-IN-PROGRESS

J.1 SUMMARY

A final part of this evaluation includes a task to sub-meter loads that customers said they would curtail for a small sample of participants in the 2004 price-responsive programs. Working Group 2 included sub-metering in this study because it offers unique opportunities to monitor site-specific energy services in ways not otherwise possible (e.g., end uses, specific pieces of equipment, and service indicators like air temperatures, and lighting levels). The sub-metering analysis will be integrated with qualitative information developed from in-depth customer interviews (e.g., management attitudes and occupant response). A summary of the status of this part of the study is provided below:

- **The sub-metering task is still in progress**. Data analyses are being conducted on a site-by-site basis for all of the points monitored. The sub-metering report will be completed early in 2005.

- **Twelve sites are currently included in the sub-metering portion of this evaluation**. These sites span each of the three primary price-responsive DR programs (i.e., CPP, DBP and DRP), and each of the states major IOUs utilities (i.e. SCE, PG&E, SDG&E).

- **Site-specific report results are being prepared for each of the twelve sites** (drafts are complete for several these). These site-specific reports are not included in this report as they are still in progress and will be reviewed first by the WG2 evaluation committee. A set of cross-cutting findings from the sub-metering analyses also will be prepared as part of the final sub-metering report.

The most significant challenge faced on this task was the problem posed by having to recruit customers for sub-metering prior to any 2004 events being called. As discussed in several other chapters of this report, only about 10 percent to a third of participants in the 2004 DBP program took load reduction actions in any of the events (the fraction varies by utility); while for CPP the figure probably between 25 and 50 percent depending on utility and event. Extensive screening efforts were pursued to maximize the probability that the sites selected for sub-metering would be sites that took load reduction actions. Despite these efforts, because of the overall low rate of curtailment for summer 2004, some of the sub-metered sites did not take actions. Most of these indicate that they are likely to take action next summer in 2005.

The majority of this appendix summarizes the work plan executed to screen, recruit, monitor, and analyze the sub-metering sites. Load impact results for the 12 sites are not yet available.

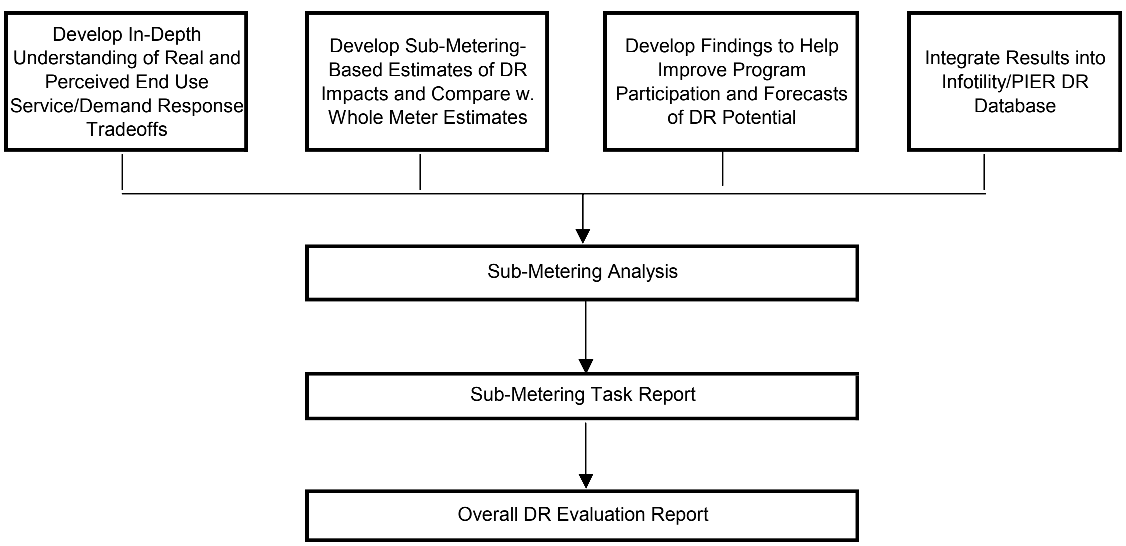
The appendix begins with a review of the sub-metering objectives and provides an overview of the steps involved in the planning and execution of the customer recruitment process, highlighting where recruitment successes occurred and where specific challenges were encountered. The various parameters for end use demand and energy services monitoring are then briefly discussed along with the technologies for measuring them. The appendix also then briefly describes the roles of the sub-metering team members in the implementation process and the steps used to install metering equipment and collect interval-metering data. The final sections of this appendix summarize the characteristics of the sub-metered sample and offers lessons learned from the recruitment and sub-metering participation process.

Appendix K provides examples of recruitment and data collection documents used in various steps of the recruitment and installation of sub-metering sites (i.e., draft customer referral letter, customer agreement letter, recruitment guide, and on-site form for development of the site-specific metering plans).

J.2 OBJECTIVES FOR DR SUB-METERING EVALUATION

Quantum originally identified several possible objectives for the sub-metering aspect of this evaluation study. Over time, these objectives were slightly revised and re-prioritized as a result of market conditions and feedback from the WG2 Evaluation Committee. The originally proposed sub-metering objectives are shown in Exhibit J-1.

Exhibit J-1
Originally Proposed Sub-Metering Objectives
for the Large Customer Demand Response Evaluation



Each of the project's original objectives presented in Exhibit J-1 are discussed below with an examination of how these objectives were met or modified in the course of pursuing monitoring projects.

Develop In-Depth Understanding of Real and Perceived End Use Service/Demand Response Tradeoffs. The key objective of the sub-metering expressed by the WG2 Evaluation Committee has been to assess both the real and perceived effects of load reduction strategies on energy services, particularly for those situations with modest load reductions as a percent of total load. Customers who carry out modest load reductions are of more analytical interest than large reductions because the impact on services is less clear.

Addressing this objective has required facility monitoring to an extent allowable under constraints of time, funding, and customer willingness to participate, and has been supplemented by qualitative interviewing of facility managers, operators, and occupants. The types of energy services (or energy service proxies) that are typically measured include end use systems themselves (e.g., lighting fixtures, process equipment and AC units), indoor and outdoor air temperatures and other key building system parameters when required. Qualitative interviewing of program participants was needed to ensure that the monitoring and qualitative data were effectively integrated to address issues such as occupant comfort, facility productivity and other experiences gained by participants in the curtailment of loads.

This objective has been largely met in the summer 2004 monitoring effort, although fewer sub-metered sites were completed than originally planned.

Develop Sub-Metering-Based Estimates of DR Impacts and Compare with Whole-Meter Estimates. Sub-metering data can be used to develop bottom-up estimates of DR impacts for sub-metered participants that can be compared to estimates of impacts measured by whole-meter interval data. Comparing these results may lead to improved understanding of the strengths and weaknesses of different whole-meter estimation methods. Sub-metering based estimates of DR impacts may be particularly important for those sites that target low impacts as a percent of total load (e.g., under 10 percent), since these impacts will be difficult to observe through whole-meter methods (see Chapter 6 and Chapter 7).

Develop Findings on What Works and What Doesn't to Help Improve Program Participation and Forecasts of DR Potential. Another important objective of the sub-metering task is to increase the understanding of what DR actions work well and which do not, particularly, from the point of view of energy service impact and customer cost to implement. Ultimately all impact data analysis should provide an enhanced understanding of end uses, technologies and customer/facility characteristics that drive impacts either higher or lower than expected. By documenting the impacts from specific strategies in specific applications and identifying cost-effective segments and implementation strategies, findings from the summer 2004 sub-metering efforts may help to identify successful practices, improve estimates of DR potential, and inform program design recommendations, marketing strategies and other areas of DR research.

Integrate Results into Infotility/PIER DR Database. A final objective of the sub-metering task is to ensure that the key data are integrated into a comprehensive, cross-study DR database developed by Infotility for the California Energy Commission's Public Interest Energy Research (PIER) program.

J.3 SUB-METERING EVALUATION PLAN

J.3.1 Participant Population Frame

In this section we review the program participant populations with respect to participant interest, suitability and availability for sub-metering.

Exhibit J-2 shows the initial participant population (accounts) that was obtained when the sub-metering effort was in the earliest stages of candidate screening and recruitment. This population was built using the CPP and DBP participant lists provided by each of the three utilities (available as of April 9th, 2004) and it provides the initial list of accounts from which sub-metering candidates were first screened. (Subsequent participant population updates were provided later in this project. The final program participation figures are provided in Chapter 4 of this report.)

Exhibit J-2
Summary of Initial (April 2004) Program Participant Population
Used for Sub-Metering Recruitment
(See Chapter 4 for up-to-date participant population)

Business Type	Total Participants (3 IOU's)	CPP Participants	DBP Participants
Commercial	**258**	**22**	**236**
Office	34	1	32
Retail/Grocery	131	0	132
Institutional	32	10	22
Other Commercial	61	11	50
Industrial and Agricultural	**178**	**21**	**161**
Petroleum, Plastic, Rubber and Chemicals	48	3	45
Mining, Metals, Stone, Glass, Concrete	30	3	28
Electronic, Machinery, Fabricated Metals	50	2	49
Other Industrial and Agriculture	50	13	39
Transportation/Communication/Utility	**37**	**14**	**23**
Unclassified	**2**	**0**	**0**
Total Accounts	**475**	**57**	**420**

J.3.2 Initial Sub-Metering Sampling Criteria

As was discussed with the WG2 Committee, Quantum's original plan was to develop a sample using a screening process with a census of the participants that focused on identifying sites that have a high probability of reducing load as a result of program participation and meet other technical requirements. Sub-metering participants were tracked within a traditional sampling matrix that identifies business type, utility, and program (as shown for the initial participant population in the previous section). Quantum sought to obtain as diverse a sub-metering population as possible, but the probability of reducing load and technical requirements led to a less diverse sample. The list of metering site selection criteria is as follows:

1. **Customers that are highly likely to opt-in for DR events**. This was applied as a pass-fail criterion as sites were eliminated that did not plan to take DR actions during summer 2004.

2. **Customers that will shed multiple loads at a site**. All else being equal, these sites were fundamentally more interesting and cost effective to study given the fixed costs of working with each individual site.

3. **A mix of business types and customer sizes across the metering sites**. A sample was sought that covers a representative range of business types and customers sizes.

4. **A mix of end uses and shed strategies across the metering sites**. A variety of end uses and shed strategies will increase the value of the sample. For example, an undesirable sample is

one that is dominated by sites that simply turn off a piece of equipment that is unique to that site, or a sample dominated by a single end use such as lighting.

5. **Ability to cost-effectively sub-meter loads and energy services of interest**. Some sites may be interesting but prohibitively expensive to sub-meter effectively for a cost commensurate with the site's potential information value. Further discussion of sub-metering costs is presented below in Section J.3.4.

J.3.3 Proposed Candidate Recruitment and Data Collection Process and Timeline

This section lists the steps for the sub-metering recruitment and data collection process as proposed in a working draft of the Sub-metering Plan submitted to the WG2 Committee in April, 2004.

1. *Initial Screening of Program Participant Lists*
2. *Telephone Screening and Recruitment*
3. *On-Site Survey*
4. *Develop Metering Plans*
5. *Metering Implementation*
6. *Data Collection*

With actual experience gained in the early stages of the sub-metering candidate recruitment process, selective modifications to this process became necessary to address some of the unanticipated challenges encountered during recruitment. These modifications did not alter the basic steps of the candidate recruitment and data collection process as outlined above. The actual practice of these steps is detailed in Sections 12.4 and 12.5 of this report.

The original timeline for completing the recruitment and data collection process was dictated in part by the expectation that sub-metering equipment would be deployed only to the end of December 2004. Consequently, milestones of the timeline were originally set as follows:

- May 10th through July 16th — Complete Sub-metering Installations
- June 7th through October 22nd — Collect Sub-metering Data
- August 16th through October 15th — Sub-Metering and On-site Data Analysis

J.3.4 Sub-Metering System Options

There are emerging monitoring technologies that offer an expanded set of options for comprehensive monitoring, data integration and remote and next-day access relative to traditional, stand-alone devices requiring periodic manual data retrieval. Yet, advanced sub-metering can be quite costly, take longer to install and require a scarcer labor skill set. In managing the recruitment and implementation of sub-metering projects, there was a needed to continuously evaluate the trade-offs between sub-metering costs, difficulty and timeliness of implementation, and the quality and extent of interval data desired. The types of sub-metering systems deployed at sites in the sub-metering sample was influenced in part by the anticipated distribution of sites across the range of approved metering costs per site. Differentiation in per site metering costs was subject to the following considerations:

- A wide range of metering technologies, numbers of points, interval granularity and levels of data access are possible across and within a cost scenario. Different cost and sub-metering levels have different timing and implementation issues associated with them as well.

- Generally, as the cost per site goes up, so does the complexity of data collection and retrieval, number of points, and time it takes to plan, order (as necessary), and install equipment.

- Higher cost sites are more likely to have more points, more sophisticated equipment, and next-day or real-time Internet access. However, in addition to costing more, these sites will also take longer to plan, install, test, and calibrate.

- Significant data resources may be obtained from existing EMCS systems even under the moderate cost cases, if these existing systems have extensive data trending and storage already enabled and implemented.

J.3.4.1 Description of Metering Approaches

Three basic approaches to end-use measurement and data collection were proposed in the initial scope of the sub-metering evaluation.

1) Accessing data being stored in an existing EMCS,

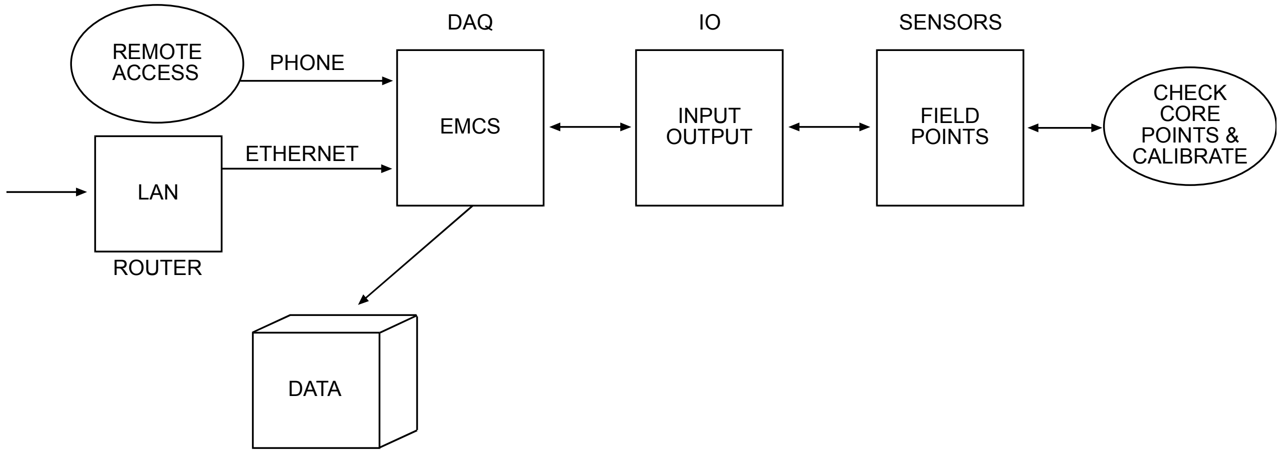
2) Adding a parallel system (so-called "N Box") to supplement the capability of the existing EMCS system, and

3) Installing an independent monitoring system (using loggers or recorders and related sensors/meters/CT's).

The approach deployed is partly determined by the existing equipment capability at the site, ease of installation, cost to implement, client preferences, customer willingness, timing or frequency with which data is needed, and other factors. Approaches can also be combined at individual sites. Each approach is briefly discussed below highlighting the advantages and disadvantages of each.

1) Existing EMCS. In this approach, the facility's existing EMCS is used to collect time-series data and make it available for access over telephone or Internet connections. Virtually all facilities with very large chillers have EMCS's that monitor sensors and provide supervisory control. Chiller power or energy consumption (kW or kWh) is not always monitored although typical points include supply and return temperatures of chilled water and outdoor air temperatures. Exhibit J-3 provides a diagram of the approach 1 data retrieval process.

Exhibit J-3
Monitoring Approach 1
using an Existing EMCS to Retrieve Data

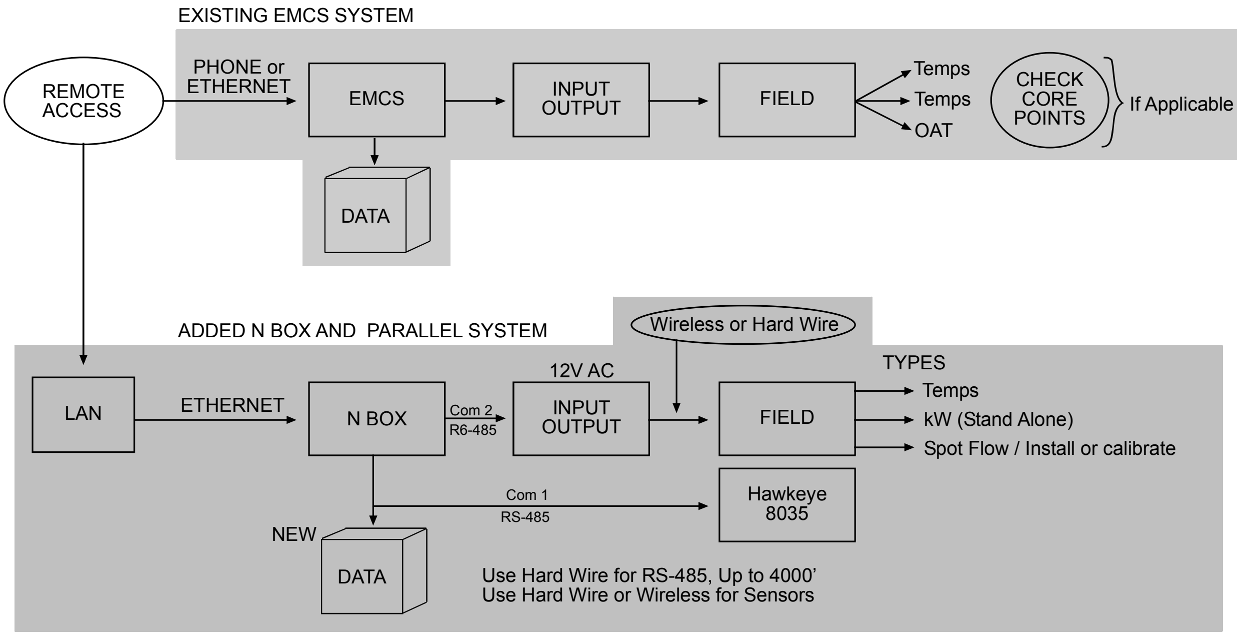


The capabilities of the EMCS must support the data acquisition activities, while maintaining proper control. EMCS functionality will not always support the data collection activities we desire. **Shortcomings include**: available memory, trending capability, CPU speed, and system architecture. In addition, the EMCS needs to have available connections through serial or parallel ports, telephone jacks, or network connection devices.

The advantage to this approach, when available, is certainly metering cost, providing, for example, by far the most cost-effective data collection plan for the metering of large chillers. Disadvantages are that one may lose some accuracy relative to the installation of an independent logger/recorder system, although cost estimates provided for this method have a substantial allowance for calibrating the existing sensors/meters. Subject to the accuracy of several assumptions about EMCS systems, this approach allows the collection of data on a weekly or monthly frequency, and provides an opportunity to collect event data real time.

2) N Box (or adding a parallel system). In this approach, an additional monitoring system is installed in parallel with the existing EMCS and provides separate on-site storage and communication capability. A parallel system may be necessary for facilities with EMCS's that have less functionality, limited trending capability, slow CPU speed, inadequate data storage capability, and so on. One parallel data collection method utilizes a web-enabled, Linux-based, embedded-PC manufactured by Enflex. The compact size and open architecture of this system allows for multiple site configurations and future expandability. The use of serial and Ethernet-based drivers allows for data to be shared in real time. The system also supplements or adds web functionality to existing EMCS systems. Exhibit J-4 provides a diagram of the Approach 2 parallel system installation and data retrieval process.

Exhibit J-4
Monitoring Approach 2
using an N Box Parallel System Installation



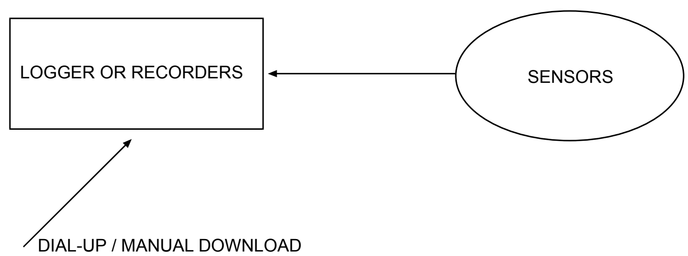
In this method, the parallel system consists of an N Box control server (with storage and software); input/output controller cards; and field sensors (temperature, kW, flow proxy variable, etc.). An ethernet or serial connection establishes communication between the parallel system, and EMCS, and allows access to stored data from the remote site.

The parallel system would collect available data from the EMCS. A proxy variable for chilled water flow will be identified, and calibrated during on-site installation. The control module collects and stores sensor data for retrieval via FTP from a remote site. A telephone connection may also be used.

The advantage to this approach, when available, is flexibility, providing a system that stores data already collected at the site and from independently installed sensors. This system architecture supports newly installed sensors, which generally have greater accuracy than existing sensors. Again, this approach also allows the collection of data on a weekly or monthly frequency, and provides an opportunity to collect event data real time. Disadvantages are that one may lose some accuracy when using existing sensors or flow meters, although calibrating existing sensors/meter largely addresses this problem.

3) Independent Monitoring (logger- or recorder-based system). In this approach, all equipment needed to facilitate measurement and data collection are installed, using either loggers or end-use metering recorders. This includes the installation of CT's, sensors, and flow meters. Quantum originally expected and proposed that the majority of the end-use metering installations for this DR evaluation project would be accomplished using this approach. The WG2 Evaluation Committee expressed a desire to minimize this approach although achieving the sub-metering goals under the constraints of the current timeline and budgets required flexible and appropriate incorporation of Approach 3 into the overall mix. Exhibit J-5 provides a diagram of the approach 3 logger or recorder installation and data retrieval process.

Exhibit J-5
Monitoring Approach 3
using a Logger or Recorder System



Loggers provide a metering approach that is self-contained and therefore the installation is less disruptive to the plant and facilities staff. Loggers are placed relatively close to the sensors that measure a given parameter, so there are no long runs of communication or power wiring (as is more common in recorder installations). Logger installations, however, require costly data collection using manual downloads (vs. telephone-based data collection normally used in recorder installations). The frequency of required manual downloads (using the equipment we recommend for this job), is about every 3-6 months. There are some limitations in using this approach, in that this lack of regular communication with the logger may result in data loss should the recorder stop functioning or meters or sensors fail/go out of calibration. Data validation and verification that data collected is accurate and complete can only be established following each manual data collection event. Loggers have the lowest removal cost, as a trip is already needed for data download. Loggers, however, provide the lowest overall metering cost, especially where the data collection needs for a given site are limited (as recorder installations and other approaches become cost-ineffective).

Recorder installations are closer than loggers to a permanent metering solution, are more invasive for the facility and staff that support a given facility, and more labor intensive during the installation. The installation process, on the other hand, requires the installation of sensors that may be spread throughout a given facility, and the installation of power and communication wiring to bring signals back to centrally located recorders. This interconnection of power and communication wiring must be installed using established code compliant methods, involving, for example, the installation of "permanent" conduit and the involvement of a licensed electrician. A clear advantage over the logger approach is having ongoing access to the data being collected, thus facilitating data validation and verification throughout the data collection period and allowing real-time review of DR events, while reducing the labor requirements of data collection. Remote communication with the recorder to collect data is facilitated via a modem and shared or dedicated phone line, using data collection software such as MV-90 or Synernet. The data is periodically downloaded to a data collection workstation using a dedicated phone line or with a shared phone line using a phone/fax switch.

The following procedures apply to the sub-metering approach that uses loggers or recorders:

1) An initial site visit is typically needed to facilitate the development of a detailed metering plan.

2) Monitoring equipment needs to be fully bench-tested and, as needed, refurbished to ensure accuracy.

3) All sensors and meters need to be calibrated using independent spot field measurements.

4) As is true for all metering approaches, a full service turnkey data collection effort is typically required spanning the recruitment, initial site visit, preparation of a metering plan, equipment installation and maintenance, and data collection and validation.

Quantum staff and supporting sub-metering subcontractors (ADM, Mad Dash, Inc (MDI)) were all turnkey providers of sub-metering services.

J.4 PARTICIPANT RECRUITMENT AND DATA COLLECTION PROCESS

This section describes the participant recruitment and data collection process as it was applied in practice. The entire candidate recruitment and data collection process is reviewed in this section noting where changes were made to the proposed process (as outlined in Section J.3.3) and how these changes impacted the outcomes of the recruitment process.

Over the summer months of 2004, sub-metering project status reports were regularly provided to the WG2 Evaluation Committee which identified relevant issues, such as the need for updated participant lists, challenges with making candidate contacts and scheduling, finding optimal candidates, and the associated administrative and per site costs. Changes to the proposed recruitment process were discussed to obtain continuous general guidance and approvals for iterative modifications to the target candidate population relative to the ongoing expansion of the sub-metering sample. Objectives for the sub-metering evaluation and the criteria for sample selection remained largely unchanged throughout the project.

J.4.1 Participant Lists and the Identification and Ongoing Reassessment of Target Population

The initial screening of candidate participants began in April, 2004, by examination of each Utility's CPP and DBP program participant lists provided as of April 9th (see Exhibit J-2, above). When the sub-metering screening and recruitment process began, the program participant population accounted for 475 accounts, representing 220 unique customers.

The initial distribution of unique customers among SCE, PG&E and SDG&E were approximately 72%, 18% and 10% respectively, and a separate database of program participants was established for the purpose of tracking the entire sub-metering screening, recruitment and implementation process. Included in this database was information obtained from Quantum's prior In-Depth survey of selected participants, as well as the Utility's respective Account Representative recommendations on which sites should not be contacted.

Each of the utilities provided periodic updates to their participant lists throughout the summer, and these were incorporated into the sub-metering tracking database. Participant population updates were found to be somewhat irregular in the number of new participants added in each iteration and in the extent of information provided about accounts; contact information for new participants were not always available with population updates. The following summarizes how each of the CPP and DBP program participant population updates (occurring after April 6th) from each utility contributed to the expansion of the sub-metering tracking database:

SCE: Significant program participant updates were provided on May 18th, July 6th, August 4th and October 27th. Information about all participating accounts was found to be complete in each iteration, and the July 6th update provided the biggest single increase in the overall sub-metering candidate population. However, this increase was almost completely confined to SCE's new DBP program participants. Early successes in sub-metering recruitment also happened to come from SCE's DBP program population; these conditions challenged efforts to stratify the sub-metering sample by utility and by program from the beginning of the recruitment cycle. The SCE CPP program participants accounted for a very small fraction of SCE's total DR program participants in all iterative updates on SCE's DR program populations.

PG&E: Updates to the DBP and CPP program populations were provided on August 17th, September 30th, and October 28th. Contact information for participating accounts was not present in these updates, although contacts for the August 17th update were provided two weeks later. While a number of promising sub-metering candidates were present in the first update (August 17th), the delayed receipt of contact information effectively eliminated the additional new sites from the recruitment pool due to the time required to progress through the steps of screening and cultivating eligible sub-metering candidates, and to install monitoring equipment with enough time to have a reasonable probability of capturing late summer DR program events.

SDG&E: Since the beginning of April, six DR program population updates were provided on a monthly basis. Program population updates were provided on May 5th and 27th, July 1st, August 3rd, and September 9th, and each was found to contain complete information needed for the sub-metering tracking database. However, each successive update showed very small incremental changes to the number of customers in the CPP and DBP program populations.

Exhibit J-6 shows the final distribution of program participant accounts by program and general account type. When this final distribution is compared to figures in Exhibit J-2, above, it can be seen that the total potential candidate population for sub-metering doubled over the course of the summer months. The nearly fourfold increase in the number of CPP program participants was most notable in this overall trend.

Exhibit J-6
Distribution of Final Program Participant Accounts by program and Business Type

Business Type	Total Participants (3 IOU's)	CPP Participants	DBP Participants
Commercial	**455**	**78**	**387**
Industrial and Agricultural	**323**	**73**	**259**
Transportation/Communication/Utility	**100**	**28**	**72**
Unclassified	**72**	**27**	**45**
Total Accounts	**950**	**206**	**763**

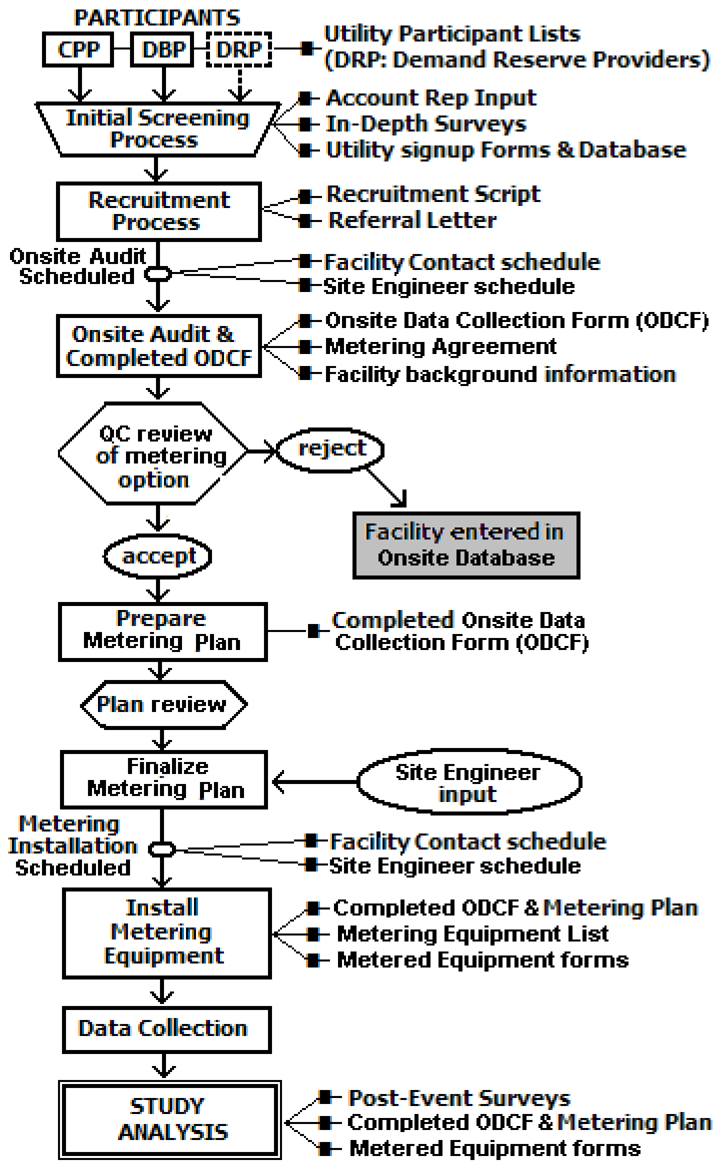
Program participants of the Demand Reserves Program were added to the sub-metering candidate pool in early August, when the WG2 and Quantum agreed that it would be beneficial to include this population in the overall DR program evaluation. The DRP candidate population is characterized by program participants recruited and signed onto the program by their respective demand reserves providers (aggregators). Although the utilities provided DRP participant populations to Quantum when this program was added to the scope of research, exploring the DRP program population for sub-metering candidates was carried out differently than the process for the DBP and CPP programs. The process for identifying and pursuing DRP sub-metering candidates is described in the following section.

J.4.2 Sub-metering Recruitment and Data Collection Process

This section details the sub-metering recruitment and data collection process as it was applied in practice. Exhibit J-7 illustrates the steps listed in Section J.3.3, above, and provides an important reference to how these steps were carried out in the execution of Quantum's sub-metering recruitment and data collection tasks. Each of the steps in this process are described below, including the ways in which they evolved to adapt to unexpected circumstances and conditions.

Exhibit J-7

Applied Recruitment and Sub-Metering Data Collection Process



J.4.2.1 Initial Screening

Quantum staff obtained the initial lists of candidate sites from each utility, and began the screening of sites based on the application of initial screening criteria to information found in utility participant databases, the In-Depth Survey responses, program signup forms and input from Account Managers regarding program marketing and their customers' participation intentions (if available). Input on both recommended and omitted sites was also obtained from Account Managers from each utility prior to the launch of the recruitment effort. Candidates were eliminated at this stage for the following reasons:

- Account Manager recommended omissions.
- Quantum's previously unsuccessful contact attempts (or refusals) during prior In-Depth Surveys.
- Sites known to rely exclusively on back-up generators to curtail loads at the revenue meter.
- Structural benefitters (CPP program only)

Originally envisioned as the first step in a linear process of recruiting sub-metering candidates, the initial screening process became an iterative process brought about by periodic expansions of the candidate pool (from program participant population updates) and by the need to reassess the sub-metering target population given the changing mix of candidate sites selected for sub-metering. For example, the first six sub-metering sites selected were all industrial sites; consequently, the target population for sub-metering recruitment was later shifted to a focus on commercial facilities, namely office buildings. This shift, required the addition of industrial sub-metering leads in favor of a more stratified sample of monitored sites, which, in turn would lead to broader utility of the findings from the summer 2004 sub-metering evaluation.

It was originally thought that utility Account Managers would be asked to contact customers that pass the initial screening criteria to explain the evaluation need and introduce them to Quantum Consulting. This step was not required but was originally thought to be a key step in augmenting the receptivity of program participants to sub-metering. However, it was also recognized that this step could be skipped if it resulted in delays in the recruitment process. In practice, Account Managers were not requested to perform this function but were routinely notified after Quantum staff had contacted a customer and determined that the customer was a good candidate for sub-metering.

As sub-metering evaluation of DRP participants was added to project scope late in early August, a different process was required for identifying sub-metering candidates and obtaining their contact information. With the exception of a small number of PG&E customer sites, the utilities could not provide DRP participant lists earlier than mid-September and contact information was not provided. Consequently, the pursuit of DRP sub-metering candidates was an independent effort from those of the DBP and CPP programs. Quantum had to rely exclusively on the DRP's active Demand Reserves Providers (aggregators) that are the primary agents responsible for recruiting and establishing contracts with program participants. The Demand Reserves Providers were contacted to explain Quantum's sub-metering evaluation and explore viable sub-metering candidates. Within a short time frame, this process yielded several viable candidates and one sub-metered site in the SDG&E service territory.

J.4.2.2 Telephone Screening and Recruitment.

As one of the work products of the sub-metering task, a scripted ***Recruitment Guide*** was developed for use in initial phone pre-screening activities. A draft of the recruitment guide was provided to the WG2 on April 9th, and is included in Appendix K.1.

A ***Customer Referral Letter*** was drafted that provides a brief description of the DR evaluation and the end-use metering activities. This letter was intended to be provided to the customer by their Account Manager prior to the initial Quantum recruitment phone call. More often, the letter was sent to the candidate by Quantum after the initial phone contact had been made. Customer contacts often requested the letter to obtain internal administrative approvals to consider the sub-metering installation. The draft of the customer referral letter was provided to the WG2 April 9th, and is included in Appendix K.2.

At the initiation of the sub-metering recruitment process in April, recruitment calls were immediately placed to participants first considered to be ideal candidates. Conversations of recruitment calls sought to obtain further information on their DR readiness, probability of participation, and the strategies to be used for DR events. Other information obtained about candidate sites includes the use of EMCS systems and their capabilities, past DR program participation, and the overall willingness and availability to participate in the sub-metering project.

From the onset, two types of detailed results were tracked for each customer contacted: 1) reasons describing why the customer was an acceptable or unacceptable candidate for sub-metering, and; 2) brief descriptions of each customer's likelihood of taking DR actions this summer and associated reasons for likely action or inaction. These reason codes are summarized in the discussion of participant dispositions in the following section of this report.

Quantum found that the telephone screening and recruitment process required significantly more time and effort than anticipated. This was a result of several factors, described in the bullets below:

- The average number of calls required to obtain enough qualitative information to screen customer willingness to host a sub-metering project was much greater than originally anticipated. Consequently, use of the recruitment guide, a prepared telephone script (see Appendix K.1), was of limited value as it could only be used for the first of several calls typically required to complete the telephone screening and recruitment process. In the latter stages of this process, an average of approximately 7 calls to candidates was needed to make a determine candidacy and willingness. Ten or more calls were not uncommon.

- A major factor in the difficulty of completing the telephone screening and recruitment process for individual participants was the frequency with which participants expressed administrative barriers to participation, uncertainty about their DR strategy or the likelihood of their participation, or their availability, ability and interest to host a sub-metering project. The following section reports findings from a mid-summer analysis of program participant dispositions regarding the willingness or ability to participate in DR events and the underlying reasons for these dispositions.

- Participant fatigue with repeat contacts by various utilities and Quantum staff played into the diminishing responsiveness of customers as the summer progressed. Messages left by Quantum's sub-metering recruitment staff at sites were typically not returned, and it was determined that no more than two messages should be left for a given customer. Even after sites had been recruited for sub-metering, or scheduled for either on-site surveys or metering installations, participant contact often proved to be difficult. For one sub-metered site, the primary site contact became completely unavailable.

On a continuous basis throughout the recruitment period, Quantum staff met regularly to analyze the results of each of the telephone screening interviews to determine whether an on-site survey should be conducted to further assess sub-metering potential. In this manner, the telephone screening process became an iterative process that both re-engaged the initial screening process of new participants (as they were obtained from each of the utilities), and considered outcomes of the on-site survey and sub-metering installation process. In practice, none of these steps were conducted independently in a linear fashion. Rather each step in the recruitment process tended to be iterative and was often influenced by findings and determinations made in the other steps. A prime example of this condition was that the iterative screening process of new candidates was heavily influenced by the types of sites first selected for sub-metering. (i.e. a changing focus to target commercial office sites after the initial sample of sub-metered sites were disproportionately process industrial sites).

The telephone screening and recruitment process often yielded information that challenged the initial determination of sub-metering candidacy of participants. In turn this required a continuous re-qualification and re-evaluation of individual candidates subsequent to almost every call, and an overall re-evaluation of the sub-metering candidate pool as well as.

The telephone recruitment and screening process terminated at the end of August in accordance with the Sub-Metering Research Plan and subsequent direction from the WG2 Committee. As of the end of August contact had been attempted for all but 31 of the 229 unique participants. Contact has been completed with 97 customers and of these, 55 met our screening criteria for consideration as sub-metering sites eligible for on-site surveys.

J.4.2.3 On-Site Surveys

Following the telephone screening and recruitment process Quantum staff narrowed the candidate list to those eligible for on-site surveys, namely those customers considered viable after passing screening criteria and who expressed willingness to participate in the on-site survey and possibly host a sub-metering project. Once determined to be eligible, Quantum sought to schedule and conduct on-site visits at the customers' participating facilities.

When engaged to conduct onsite surveys, Quantum and its subcontractors were expected to follow each site through the process of developing metering plans, installing metering equipment, and in cases, be the primary agent for collecting data. Later in the recruitment process, a Demand Reserves Provider was engaged by Quantum's sub-metering team to conduct an on-site survey for one of their Demand Reserves Partnership (DRP) Program customers.

In May, a training session was held for subcontractors to orient them to the overall purpose and steps of the sub-metering recruitment, implementation and data collection process, and to familiarize them with the tools necessary to complete all steps in the process. Two remaining subcontractors, ADM Associates and Mad Dash, Inc. (MDI) were the primary agents in conducting on-site surveys and installing metering equipment. Both were adept at sub-metering projects involving synergistic recorder devices per the third metering option described above in Section J.3.4.1.

The information and documents the Quantum team needed to conduct the on-site surveys include a background information document on the participant (contact, location, type of facility, qualitative information), a ***Monitoring Agreement*** to deliver to the participant for signature, and the ***On-Site Data Collection Form (ODCF)*** for recording all essential information from the on-site survey**.**

Candidates who make it through the recruitment process, and were confirmed as sub-metering nominees, were provided with a ***Monitoring Agreement.*** When signed, this agreement confirmed the customer's willingness to host a sub-metering project, authorized the Quantum team to install metering equipment, and set basic terms and conditions for the sub-metering installation. A template of the monitoring agreement is provided in Appendix K.3. Utility Account Managers were typically notified of on-site surveys once they were scheduled. This was typically the last point at which Account Managers were engaged for any further input sub-metering candidates.

The inventory survey form used in this process was developed by Quantum staff in conjunction with ADM Associates and referred to as an ***Onsite Data Collection Form (ODCF);*** this form is included in Appendix K.4. The ODCF was developed as a survey inventory form that detailed items such as site operations, energy services utilized, curtailment strategy, what controls they currently have in place, and a broad range of other site-specific parameters. The ODCF is a key document in the sub-metering installation, assessment and data collection process. Information recorded in the ODCF during on-site surveys provides the basis for a final determination of the suitability of a participant for sub-metering, informs the development of a sub-metering plan and provides a site orientation and guide for equipment installers. ADM collaborated with Quantum staff in the development of a suitable ODCF.

As intended, completed on-site surveys provided the basis for determining the suitability of a participant for sub-metering. On-site surveys were conducted at 18 program participant locations of which 12 were selected as sub-metering sites. Sites determined to be ineligible for sub-metering were typically rejected for lack of a coherent curtailment strategy, probable failure to meet load shedding minimum requirements, or a low probability of participation due to operational concerns at the site.

J.4.2.4 Development of Metering Plans

Metering plans were used to solidify metering strategies and guide the sub-metering installations. Following the on-site survey and the determination that a participant was a sound and willing metering prospect, Quantum's team or their subcontractors prepared metering plans to monitor the load components involved in DR events. Typically, the individual who conducted a on-site survey also was responsible for proposing a sub-metering strategy to the Quantum team, as they were often the individual managing metering installations for the site. Next, the ODCF's were reviewed together with the preliminary metering plan. The proposed metering strategy was typically modified based on discussions and recorded at a level of detail that allowed each metering installation to be assigned.

One challenge in this process was striking the appropriate balance between managing the number of loads monitored, project costs, and the extent and utility of sub-metering data that would be obtained.

It was originally intended that staff to the WG2 Committee would review the metering plans, although this was later agreed to be unnecessary as an internal review proved adequate to refine each metering approach. Formal written metering plans were deemed unnecessary. This process delivered metering strategies that were well understood by equipment installers whether they conducted on-site surveys or not, and it reduced the staff time and subcontractor costs associated with the original metering plan review process.

J.4.2.5 Sub-metering Project Installation

Either Quantum, ADM or MDI staff, installed metering equipment. Participant contacts were sometimes active in contributing their time and other resources to the sub-metering installation and data collection process. Both subcontractors, ADM Associates and MDI, assisted Quantum in the process of maintaining an inventory of sub-metering equipment as well as conducting equipment bench tests and post-installation testing and programming of monitoring and data recording devices.

Upon completion of the metering installation, installers were asked to complete a ***Data Point Summary*** that effectively mapped the end-uses to their respective recorder channels. An example of the template data point summary form is provided in Appendix K.5. This document along with additional forms for documenting nameplate data and other specifications were completed as needed.

In nine of the twelve sites monitored, and independent recorder system was used for monitoring (3rd type of monitoring system as described in Section J.3.4.1). These systems were self-contained and were required three or fewer days to install. Once metering equipment was in place, either a new or customer-supplied phone line was installed to allow for remote interrogation of the data recorders. In cases when the participant was responsible for installing or extending phone lines from their own communications systems, considerable delays where encountered in the ability to interrogate recorders remotely. For one of these participants, Quantum staff returned to the site on two occasions to manually download data.

Quantum was able to utilize EMS data for three of the sub-metered sites, though not entirely by the means described in monitoring methods 1 & 2 (as described in Section J.3.4.1 and Exhibits J-4 and J-5). For two sub-metered office building complexes, the customer or their energy services representative agreed to trend, store and deliver EMS data for specified end uses. In each of theses two cases, Quantum commissioned the installation of devices to monitor additional data points not originally monitored by the participants' EMS. The third case was a hybrid of metering approaches 1 & 2 as it involved accessing data from the EMS of a college campus, as well as the installation of six ethernet gateways in six buildings to establish curtailment performance of each building. This system was the most costly to install as it involved several site visits over several months and required a high level of interaction with site energy managers.

Onsite Energy, a Demand Reserves Provider (Aggregator) in the DRP program, acted as Quantum's subcontractor for the sub-metering of the only DRP Site included in the sub-metering sample. Onsite was responsible for all customer contact including the installation of monitoring equipment that supplemented data obtained from the site's EMS.

J.4.2.6 Data Collection

This section provides an overview of the process for collection of sub-metering interval data from monitored sites, noting significant events and challenges. Whole-facility revenue meter data for each site was obtained directly from the respective utilities. The methodology for analysis of sub-metered data is covered in Section J.5 along with the collection of qualitative data, and notable sub-metered data collection issues specific to each sub-metered site is discussed below in Section J.6

For the nine sites where data recorders were used, 5 or sometimes 15-minute interval data was stored in recorders until interrogated remotely by use of dedicated phone lines. In two instances monitored data was downloaded manually at a site where the customer had failed to install a phone line extension, and the primary contact became non-communicative.

For six sub-metered sites where ADM had installed data recorders, ADM uploaded, parsed and delivered sub-metering data to Quantum in Excel spreadsheet files. Quantum had maintained a redundant capability to interrogate recorders that ADM had installed, and was principally responsible for conducting all data collection tasks for facilities where MDI or Quantum had completed installations

For two of the three sites where monitoring data was extracted from EMS systems, either a customer contact or the DRP aggregator (Onsite Energy) provided sub-metering data files by email to the Quantum Team.

Interrogation of installed sub-metering equipment for raw data is being carried out on an ongoing basis. Capabilities for storing and trending raw data at two of the three sites that utilize EMS systems have been maintained, and the number of sub-metering channels have been expanded relative to what was possible for an analysis of events in summer 2004. A third, DRP site changed ownership in early October and continued DRP Program participation by the new owner is uncertain along with their willingness to continue participation in the sub-metering project.

Despite prior determinations of a high probability of participation, three of the twelve sub-metered sites did not participate in DR events in Summer, 2004. For two of these sites there was only one possible DR event in which they these customers could have participated; sub-metering equipment was installed in time to capture the event for one of these two sites. There were two possible DR events for the third site, and monitoring equipment was in place to capture the latter event.

J.5 SAMPLE SELECTION AND DISTRIBUTION

This section covers the interim assessments of the candidate population and customer dispositions toward sub-metering projects and the likelihood of participating in DR events. Candidates rejected after on-site surveys were conducted are discussed along with final outcomes of the recruitment process for 2004 in terms of characteristics of the sample and its distribution by utility, program and business type.

J.5.1 Interim Assessments of the Recruitment Process

Throughout the candidate recruitment process, results of each attempted contact, updated contact information, candidate status and new site information were continuously added to the sub-metering tracking database. These parameters were tracked with the purpose of conducting interim assessments and documenting final outcomes of the recruitment process.

Interim assessments of the recruitment process were conducted to evaluate how much of the candidate populations had advanced through the stepwise process of initial screening, telephone contact, onsite surveys and metering installations. Exhibit J-8 shows the *Candidate Screening Task Summary Table* of the sub-metering tracking database as assessed on August 3rd, 2004; it shows that installations at the twelve sub-metered sites had been planned or completed at that time. Figures in this table represent the number of unique participants (not accounts) that were the focus of the tracking process within the sub-metering tracking database. Although participant accounts were the basic unit of this database, unique participants (customers) were the focus of tracking efforts because account contacts were typically common across multiple accounts belonging to a unique participant (i.e. discreet at the level of unique participants), and advancement through the recruitment process was accomplished by interaction with these unique participant contacts.

Exhibit J-8
Candidate Screening Task Summary (as of August 3, 2004)

	PG&E	SCE	SDG&E	Total
Current Total Participant Accounts	66	434	56	556
Unique Participants (Customers)	40	169	27	236
Date of Most Recent Participant Population Update:	4/6/2004	6/7/2004	5/5/2004	
Current Total Unique Contacts Provided to Date (8/3/2004)	**40**	**169**	**27**	**236**
Candidates Pre-Screened - Never Phoned	1	8	3	12
Unsuccessful Contact (Multiple messages unreturned / Bad contact info)	15	54	4	73
Sites Interviewed by Phone - Rejected for Onsite Surveys	5	61	6	72
Sites Considered for Onsite Surveys / Omitted by Type or Request	12	34	11	57
Completed Onsite Surveys Rejected for Submetering	1	3	2	6
Total Rejected Candidates (unique prospects)	**34**	**160**	**26**	**220**
Submetering Installations Planned / to be Completed	2	3	1	6
Submetering Installations Completed to Date (data avaialable)	4	2	0	6
Total Candidates Selected for Submetering	**6**	**5**	**1**	**12**

This table reveals elements of the sequential filtering process by which candidates were eliminated from eligibility for sub-metering. Figures in each category of rejected candidates indicate how many candidates were screened out in the screening sequence. For example, in the category of "sites considered for onsite surveys / omitted by type or request" there were 57 total sites that had progressed to consideration for on-site surveys, but were eliminated by the participants unwillingness to host a sub-metering project, or by changes to the target candidate population dictated by the type of sites that first entered the sub-metering sample (i.e. revisions to the target population later favored commercial offices over additional industrial process sites as the first six sub-metered sites were industrial customers).

In short, all participants were considered viable candidates for sub-metering until eliminated in the progression of eligibility screens. In several instances, new information about eliminated candidates or other changing circumstances of the recruitment process led to the reinstatement of candidates as eligible for sub-metering.

J.5.2 Participant Dispositions Regarding Sub-metering and Participation in DR Events

The sub-metering tracking database contains a wealth of information about candidates' attitudes toward participating in DR events and the prospect of hosting a sub-metering project.

Based on information collected from the telephone recruitment and screening calls conducted through of mid-August, disposition data on the likelihood of participation in DR events was recorded for 239 customers in the sub-metering tracking database, covering approximately half of all unique participants. This information was instrumental in determining candidate eligibility for sub-metering projects.

The disposition data allowed for the separation of the 239 participants into two groups; 54 % of these participants indicated intent to curtail during DR events and 46% expressed that they were 'unlikely' participants. Disposition information qualifying candidates as unlikely to participate in DR events and ineligible for inclusion in the sub-metering sample was essentially the same information in that if a participant was not likely to curtail, they were not likely to consider (or be considered for) hosting a sub-metering project.

The 'likely' and 'unlikely' to curtail groups could each be further broken down into approximately ten categories of primary reasons that qualify the intent to participate or avoid DR events. Of the group not intending to participate in DR events, 37% of unique participants indicated that they either did not have a curtailment strategy defined or that they wouldn't curtail to avoid operational disturbances or occupancy discomfort from reduced energy services. 17 % of these participants indicated they either had no additional load to shed or could not meet minimum program demand reduction requirements. Other significant reasons for not participating in DR events include internal administrative or institutional barriers, pending changes in facility ownership or location, incompatibility of baseline methods with facility load patterns, insufficient program incentives or a lack of understanding of program rules.

Participant dispositions that fell in the 'likely to participate' group revealed some interesting findings. 13 % of these likely participants intended to use back-up generation for some or all of their load reduction; these candidates were undesirable for sub-metering. About 11 % of willing participants were either structural benefitters in the CPP Program (who intended to curtail but would otherwise benefit from the CPP tariff structure if they did nothing), or were 'free riders' in the DBP program (who expected to bid load curtailments in the event that their normally scheduled operations would yield load reductions). 27 % of likely participants indicated a low probability of curtailment (less than 20% for a given event), and within this group nearly two-thirds of participants indicated they thought the baseline method for measuring curtailment was problematic. The remainder of the low probability group cited consideration of likely production and operational disturbances or occupant (tenant) discomfort as the primary constraint on frequent participation. Given the objectives of the sub-metering evaluation (per Section J.2), none of these 'likely' participants were considered as desirable candidates for sub-metering projects.

The remaining "likely to curtail" participants showed a moderate to high probability of participation; The sub-metering target population was largely confined to this group which accounted for 26% of all 239 participants from which dispositions could be discerned. At just over 60 eligible participants, the field of sub-metering candidates was considered to fall short of expectations held at the beginning of the sub-metering recruitment process.

J.5.3 Sub-metering Candidates Rejected Following On-Site Surveys

Six candidates that were eventually rejected for sub-metering had advanced as far as having participated in on-site surveys. These are sites that had passed the telephone screening process although at the conclusion of this prior step, there was often uncertainty regarding the eligibility for sub-metering. Although on-site surveys required a substantial increase in demand for staff resources relative to telephone screening, there are several reasons why the uncertain cases advanced to the on-site survey step.

The common justification for onsite surveys in these uncertain cases was simply that more information was needed about the candidate. The additional information needed almost always fell into the categories of discerning what the candidates' intended DR strategies were, and if they were well suited to the programs in which they were enrolled. As discussed in the prior Section J.5.1.2 on candidate dispositions, very often candidates had either not developed a DR strategy at all or had not developed it to a level where it could be efficiently executed in the event of a day-ahead or day-of event notification. Others were uncertain if their intended curtailment strategy would meet minimum program requirements (e.g. 100 kW minimum reduction for DBP events), justify their own costs of participation, or how it could carried out without significant disruptions to site operations or occupants.

In short, program participants were in need of technical assistance and were either unaware, skeptical, or couldn't otherwise make use of the Technical Assistance Incentive programs associated with the CPP and DBP programs. After some discussion with the WG2 committee it was agreed that the Quantum team could provide some level of technical assistance to attractive sub-metering candidates regarding their DR strategies in the interest of augmenting the possibility of their hosting a sub-metering project. It was with this understanding that members of the Quantum team would be able to interactively advise the candidate on effective DR strategies while conducting onsite surveys.

This was the approach taken for most of the on-site surveys that were eventually rejected for sub-metering. The following briefly describes each of the six candidates that received on-site surveys but were eliminated from the sub-metering sample:

1) *County Government Office and Criminal Justice Complex:* Buildings in this 1.0 million sq. ft. complex were constructed between 20 and 35 years ago and house administration offices, a courthouse and a jail. The site has 3.0 MW of self-generation capacity, but was considering mostly lighting reductions for curtailment in the DBP program. MDI was dispatched to conduct the onsite survey and discuss with the site energy manager an appropriate DR strategy. MDI provided recommendations to the customer in writing on August 1st. The participant opted out of the candidate pool for sub-metering as they did not further develop DR strategy and didn't participate in DBP events.

2) *Performing Arts Center and Charter School:* An on-site survey was conducted for this candidate before the survey process had been fully defined. There was no utility Account Manager assigned to this facility and the facility manager was not well informed about the CPP program. He had considered lobby and office lighting curtailment, but didn't know how much load could be shed. The on-site survey revealed that intended load reductions were so small that the customer would actually be penalized for participation. The customer eventually dropped out of the CPP program.

3) *Pharmaceutical Office and Laboratory:* This customer was considering for HVAC curtailment in their 18,000 sq. ft. facility, but was uncertain how much load could be shed subject to space conditioning requirements for the laboratory. Findings of the on-site survey and discussions with the facility Director concluded that the minimum DBP bid requirement of 100 kW could not be attained.

4) *Plastic Pressure and Vacuum Forming Facility:* This candidate operates within a 7,500 sq. ft. facility and had no concerns about participating in the DBP program. Their DR strategy was simply to modify work shifts so that they could shut down plastics manufacturing and assembly equipment in order attain the 150 KW load reduction goal. This site was rejected for sub-metering as the simple elimination of equipment loads was unlikely to provide meaningful insight into curtailment strategies.

5) *Advanced Metal Heat Treatment Facility:* This customer operated a 12,000 sq. ft. facility Similar to the previous customer (4), the DR strategy was to modify work shifts in order to be able to shut down electric furnaces. Again, the simple elimination of equipment loads was unlikely to yield meaningful insight into curtailment strategies.

6) *Specialty Food Manufacturing Facility*: This 200,000 sq. ft. facility was in the process of identifying which of its equipment loads could be shifted to a back-up generator (BUG) in the event of DBP notification. It was initially uncertain whether this customer would rely exclusively on their BUG as a load reduction strategy as they considered other loads for actual curtailment. Had this been the case, the combined effects of load shedding and activation of the BUG could have provided an interesting sub-metering case study. However, the customer opted only to rely on the BUG for curtailment in DBP events.

One other commercial office site was considered, but a formal on-site survey was not completed. A brief visit by a member of the Quantum team led to the exploration of a DR strategy with the customer, although it became clear that they were unlikely to reach the minimum 100 kW curtailment requirement of the DBP program.

J.5.4 Sub-metering Sites Selected for the Summer 2004 Evaluation

While the sample size of the summer 2004 sub-metered sites fell below Quantum's original expectations, the sample served the evaluation's sampling criteria quite well. Nine of the twelve sampled sites participated in a limited number of summer 2004 DR events, and of these, curtailments were recorded by sub-metering equipment at six sites. Planned and actual DR strategies at sub-metered sites involved the curtailment of multiple, diversified end-uses across a range of customer types. The remainder of this section focuses on how the 2004 sub-metering sample was stratified by program, utility and customer type. As an overview, the following list shows the allocation of sub-metering sites by program utility and program:

1) SCE / DBP – 5 sites
2) PG&E / CPP – 3 sites
3) PG&E DBP -- 2 sites
4) SDG&E / DBP – 1 site
5) SDG&E / DRP -- 1 site

A description of each of the sub-metering sites and the analysis of their respective demand response experiences is provided in Section J.6.

Exhibit J-9 shows that PG&E and SCE each had five sub-metered participants enrolled in their programs whereas SDG&E had one DBP participant and showed a second enrolled in the DRP program.

Exhibit J-9
Recruitment Contact Task Summary (as of August 3, 2004)

	Total On-Site Surveys Completed	On-Site Surveys Rejected for Submetering	Metering Instal-lations Completed	Number of Sites with DR Events Captured	Number of Sites with DR Events Not Captured	Number of Sites Not Participating in DR Events
Site Totals:	18	6	12	6	3	3
By Utility:						
PG&E	7	2	5	3	0	2
SCE	7	2	5	2	2	1
SDG&E	4	2	2	1	1	0
By Program:						
DBP	12	4	8	2	3	3
CPP	5	2	3	3	0	0
DRP	1	0	1	1	0	0
By Business Type:						
Commercial	9	3	6	2	3	1
Industrial	9	3	6	4	0	2

Exhibit J-9 shows the allocation of the sub-metering sample by program. The Quantum team felt it was a success to secure a sub-metering project within the DRP Program, given the late addition of the DRP program to the scope of the sub-metering evaluation, and the alternative means of recruiting participants for sub-metering. Of the remaining eleven sub-metered sites, the distribution approximates the proportion of total participants found in the CPP and DBP programs across all utilities. All of the sub-metered sites in the SCE service territory were DBP program participants as is representative of the fact that a very small proportion of SCE's total DR program participants were enrolled in the CPP program. Three of PG&E's five sub-metered sites were CPP customers and the remainder DBP participants. Excluding the one DRP site, the only sub-metered site enrolled in SCE's DR programs was a DBP customer.

Exhibit J-9 also shows that the number of commercial and industrial on-site surveys and sub-metered sites was equal. Obtaining this balance required a shift in the screening criteria midway through the recruitment process. As has been mentioned previously in this chapter, the first six sites actually completed for sub-metering projects were industrial sites, although two commercial project sites had also been selected for sub-metering at the time of this shift. Consequently, in the latter half of the recruitment cycle, remaining industrial sites were all but eliminated from the candidate pool as a concerted effort was made to focus on commercial candidates, especially large office properties.

Exhibit J-10 reveals the final allocation of all participant accounts for the CPP and DBP programs by business type along with the allocation of sub-metered sites. When compared to the total distribution of DR program participants, the sub-metering sample is shown to be slightly skewed toward the industrial and agricultural customer categories. There is no representation of retail and grocery customers and the electronic, machinery and fabricated metals industries in the sub-metering sample, despite the prominence of these subcategories in the DR program populations. Another omission in the sub-metering sample is the absence of sub-metered commercial customers within the CPP program. Beyond these omissions, the allocation of sub-metered sites reflects a considerable diversification of sub-metered sites and a reasonable stratification of sites across business types.

Exhibit J-10
Distribution of Final Participant Accounts and Sub-metered Sites by Business Type

Business Type	DR Program Totals (3 IOU's)		Critical Peak Pricing Program		Demand Bid Program	
	Total Partici-pants	Sub-metered Sites	Total Partici-pants	Sub-metered sites	Total Partici-pants	Sub-metered sites
Commercial	**455**	**5**	**78**	**0**	**387**	**5**
Office	60	3	11	0	52	3
Retail/Grocery	170	0	3	0	167	0
Institutional	98	1	36	0	63	1
Other Commercial	127	1	28	0	105	1
Industrial and Agricultural	**323**	**6**	**73**	**3**	**259**	**3**
Petroleum, Plastic, Rubber and Chemicals	64	1	7	1	57	0
Mining, Metals, Stone, Glass, Concrete	53	1	4	0	50	1
Electronic, Machinery, Fabricated Metals	101	0	32	0	74	0
Other Industrial and Agriculture	105	4	30	2	78	2
Transportation/Communication/Utility	**100**	**0**	**28**	**0**	**72**	**0**
Unclassified	**72**	**0**	**27**	**0**	**45**	**0**
Total Accounts	**950**	**11**	**206**	**3**	**763**	**8**

J.6 SUB-METERING DATA ANALYSIS

This section describes the methodology for site evaluations and the qualitative research that helped to complete the narrative participants' process for executing DR strategies. The description and summary results of each of the monitored sites in the sub-metering sample are provided in the following Section J.7.

The two primary objectives of the analysis of individual sites are to perform impact evaluations by use of two baseline methods and to understand and explain the patterns of individual end-use and whole-facility load curves associated with curtailment events. The latter objective is central to detailing how DR strategies are put into practice and to understanding the end-use, energy service and demand response tradeoffs. As set out in Section J.2, telling the story of individual participants' curtailment practices in the field will characterize what works and what doesn't, and will inform the development of program participation and forecasts of DR potential. A key to meeting these objectives is the qualitative research that accompanies the data analysis; this section will also provide a description of the process of collection and integration of qualitative data.

J.6.1 Curtailment Load Profile Analyses

The process for obtaining end-use interval data from the sub-metered sites was described above. Once the interval data was validated in Excel files, data for each site's monitored end uses and temperature sensors were uploaded to a SAS database that contained participant's whole-facility revenue meter data previously provided by the respective utilities. Revenue meter and recorded sub-metering data was efficiently integrated within the SAS database, and key operations were programmed which allowed for the proper identification and application of DR event and baseline data (per each utility and DR program), to each discreet analysis of participants' curtailment events. SAS programs were run on the sub-metering data to export all relevant data to Excel graphic templates in order to obtain standardize, comprehensive graphic output packages which show whole-facility and individual curtailed end-use load shapes, as well as relevant indoor and outdoor temperatures on event and baseline days.

The package of load profile graphs for each of the sub-metered facilities' DR events is central to the discussion and findings of the individual sub-metering reports. The sequence of Exhibits J-11 through J-14 provide a simplified example of how a series of load profile graphs characterize a given curtailment event at one of the sub-metered facilities. Baseline days presented in these exhibits are those determined by the three-day baseline method as described in Section 6.1.

Exhibit J-11 shows the revenue meter loads for event and baseline days of one of PG&E's CPP customers that participated in a September 10th, 2004, critical peak pricing event. Clearly, the whole-facility load drops precipitously at the beginning of the six-hour curtailment (shaded) period; the event day load remains below those of the average and individual baseline days for the duration of the event. The difference between the average baseline and event day load curves shows that the whole-facility load curtailment ranged between 10 to 90 kW over the event period.

Exhibit J-12 shows how curtailed lighting loads contributed between 20 and 30 kW of curtailed load to the whole-facility curtailment for most of the event period. Exhibit J-13 shows how HVAC package units in the production area of the facility initiate the whole-facility load drop at the beginning of the curtailment period (See Exhibit J-11) and contributed between 10 to 40 kW to the whole-facility curtailment as they cycled through the first five (of six) hours of the event period. Production operations in the facility typically terminate at 5:00 PM, and evidence of this can be seen in each of the Exhibits J-11, J-13 and J-14. A comparison of Exhibits J-13 and J-4 show that when the HVAC package units in the production area are curtailed, indoor temperatures in the production area also rise by an average of two degrees (F).

Exhibit J-11

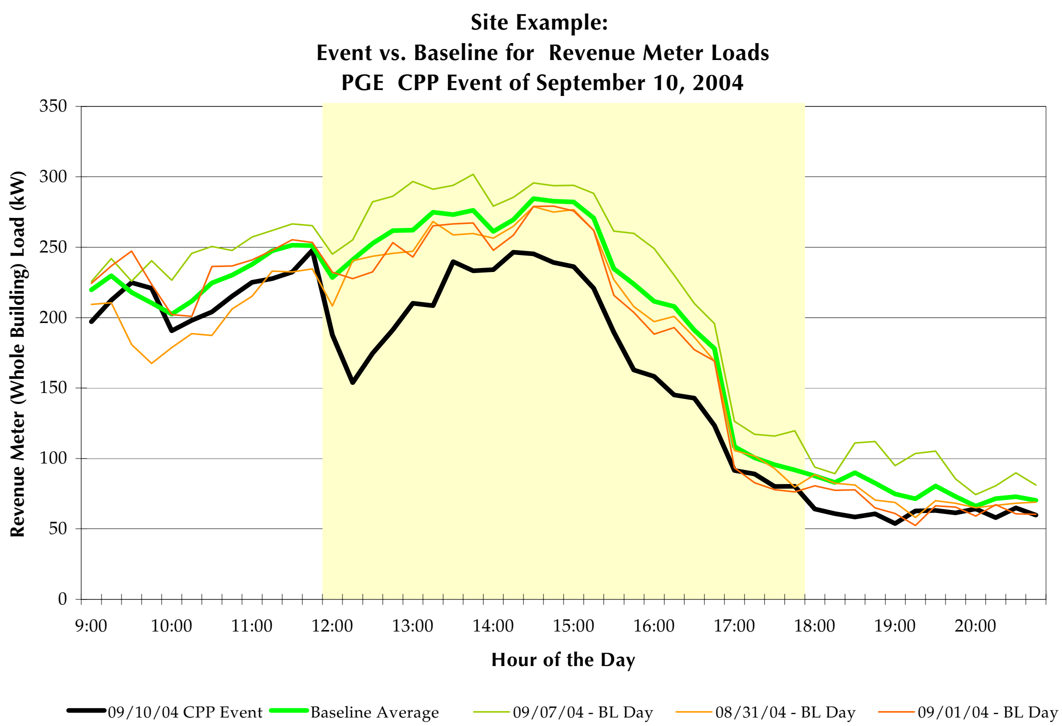


Exhibit J-12

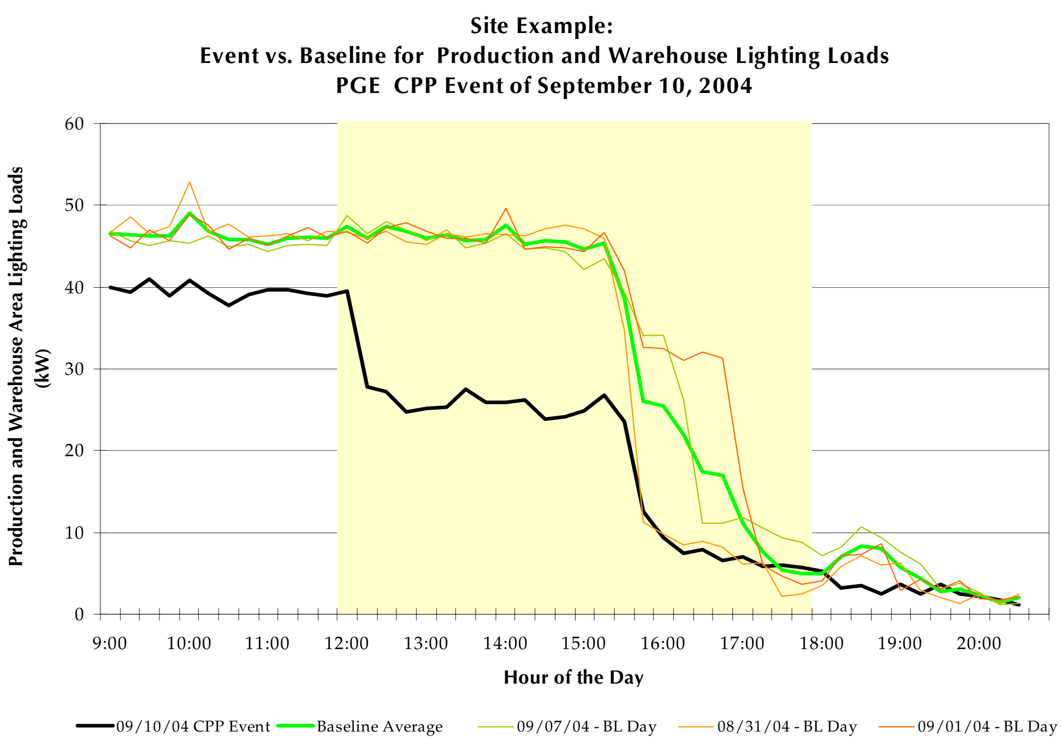


Exhibit J-13

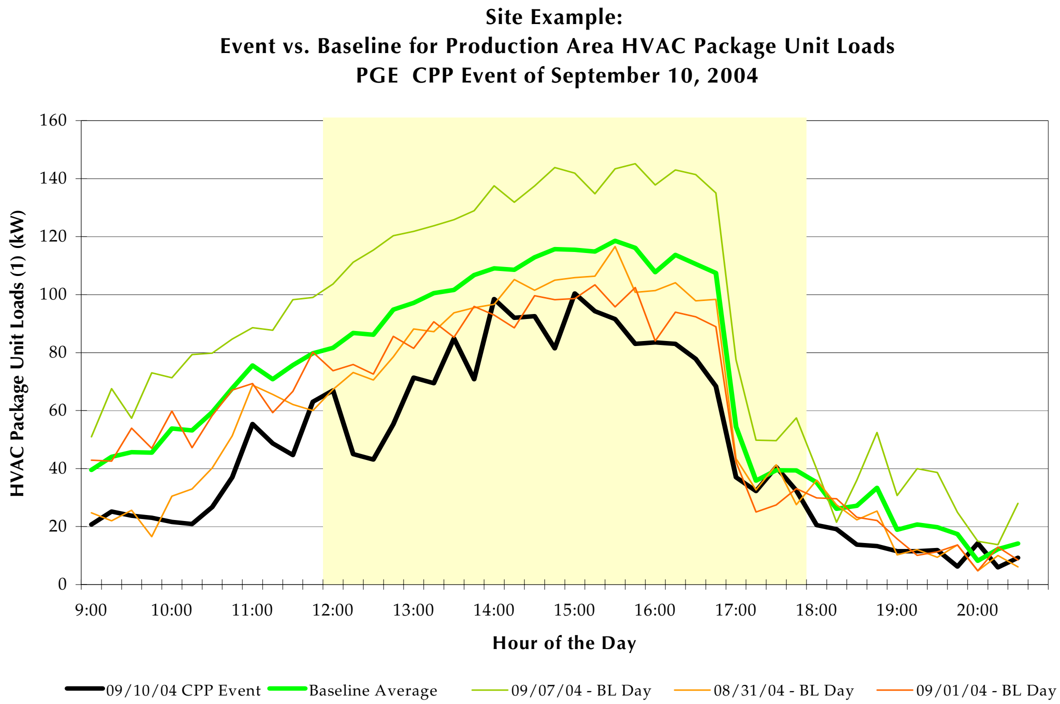
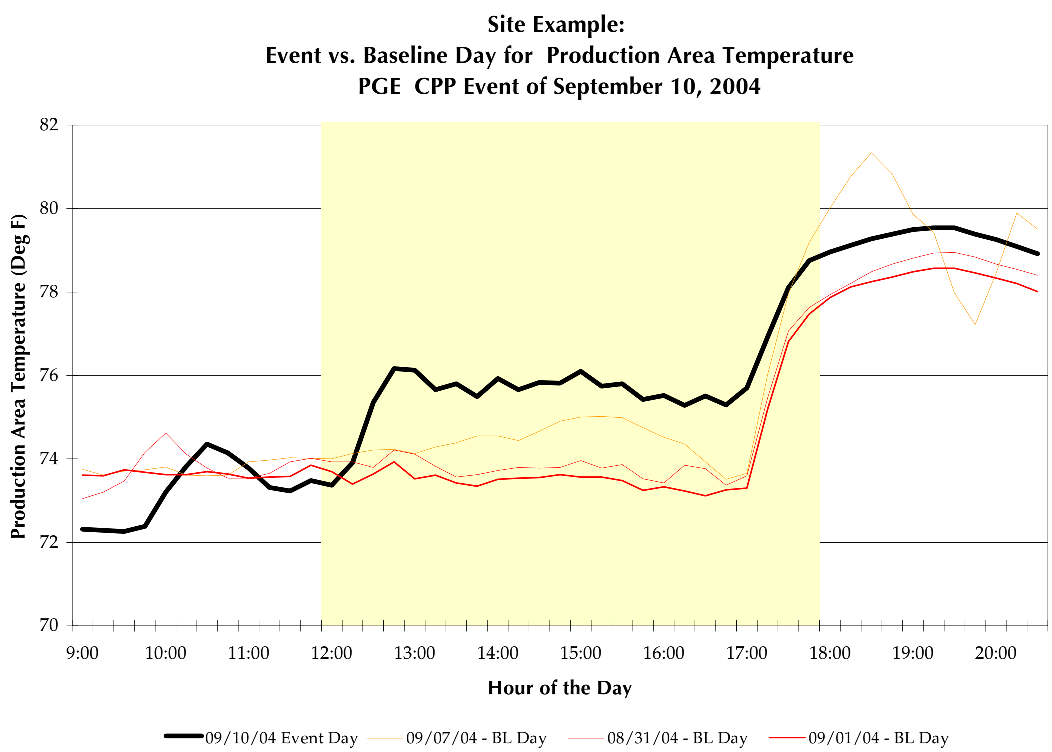


Exhibit J-14



All recorded elements of the curtailment event, including graphic outputs (as shown in Exhibits J-11 through J-14) and qualitative data, were compared and contrasted in order to piece together the story of the event as provided in the sub-metering site reports. Non-curtailed loads were sometimes also examined to understand how normal fluctuations of non-curtailed end-uses contributed or detracted from measurement of curtailment seen at the revenue meter. The intended and actual curtailment strategies (as reported by facility contacts), were examined along with the individual end-use load profiles as shown above to discern how well facility energy managers anticipated and executed DR strategies.

J.6.2 Load Impact Analysis

Drawing on the analytical methods applied in the analysis of Chapter 7, the SAS sub-metering database was also programmed to generate tables of average kW impact measurements for the DR events captured by monitoring equipment. This analysis looks at impacts of individual sub-metered end uses and at the revenue meter level. Measuring impacts at the revenue meter is performed for sub-metering sites to check against values previously calculated for the site in a separate analysis as described in Section 7.2.

Two baseline methods are applied in the sub-metering impact analysis. The standard three-day method, as described in Section 6.1, is applied as it is the method used in the settlement process by the utilities and it is the method portrayed in the graphic representation of curtailments in the curtailment load profile analysis as described in Section J.6.1, above, and as presented in Exhibits J-11 through J-14. The second baseline method used in the sub-metering impact evaluations is the 10-day adjusted method as described in Section 6.1.

By applying both baseline methods, the impacts of individual end uses can be compared. The sub-metering impact analysis does not evaluate or compare the efficacy of these baseline methods at the level of monitored end-uses. Rather, two impact figures are reported for each end use in each of the DR events analyzed for a given monitored site.

J.6.3 Qualitative Research and Analysis of Sub-metered Sites

The data collection process supporting qualitative research of sub-metered sites focused on collecting information on topics that help to explain the quantitative sub-metering results. Qualitative data was derived from several inputs at various stages of the recruitment and data collection process. The most significant examples include initial information from participant lists and Account Managers, telephone screens, post-event surveys, and field reports from equipment installers; each source provides additional insight into the effects of the DR actions and the customer's perceptions of those impacts.

Qualitative data for each site had been recorded throughout the process of screening, recruiting, planning and implementing sub-metering projects. Successive interviews and less formal conversations were typically conducted with one primary contact at the sub-metered facility that dealt with all aspects of the recruitment, planning and implementation of the site's sub-metering project. These individuals were usually the sites' building operators, facility or energy managers, though they often included more senior site level managers (e.g., general managers, production managers). In short, examples of this type of information that qualitative interviews documented include the following:

- Intended DR actions,
- Actual DR actions taken,
- The customer's explanation for discrepancies between the intended and actual actions,
- The systems and processes used to implement the DR actions,
- Areas in which the customer would like assistance in expanding or refining their DR actions,
- Ex ante DR customer perceptions of the likelihood and extent of impacts on occupant comfort and productivity,
- Ex post effects on occupant comfort,
- Ex post effects on productivity,
- Expected and actual costs associated with any comfort and productivity effects, and
- The costs associated with physically taking the DR actions (e.g., software, hardware, staff time, etc.).

Toward the end of the summer, information gaps in qualitative data for each site were identified. Typically, gaps were related to the ex post effects of DR actions, namely a lack of knowledge about events the site had participated in, actual curtailment strategies deployed (versus planned), and various attitudinal positions held by site energy managers at the conclusion of the summer 2004 programs.

For each of the twelve sub-metered sites, a site-specific post-event/end-of-summer survey was attempted. The post-event survey used was the same survey instrument as that identified in Appendix D of this report. The goal of the post-event surveys was to obtain a detailed understanding of participants' curtailment activities during the three most recent program events. This included collection of information on whether they attempted to bid and/or curtail loads for these events, the type of actions they took, their estimated load reductions and the impacts they experienced as a result of their curtailment. Lastly, they were asked about their perceptions of the notification process, perceptions on the future of the California electricity market and whether or not they intended to participate in future DR events.

The post-event surveys were indispensable to rounding out the narratives of DR strategies and the broader institutional behavior of sub-metered sites during DR events. Additional questions were typically appended to the standard post-event surveys for the twelve sites that addressed specific information gaps relevant to the applied sub-metering strategy for each site. Although two of the twelve sub-metered sites could not be reached for post-event surveys, the process of integrating post-event surveys with the final steps of the qualitative research was highly effective in terms of serving most, if not all, of the objectives of the sub-metering evaluation. Yet, with time there is a certain amount of entropy to the quantitative information on sub-metered sites and the ongoing ability to sub-meter and understand the institutional behavior of program participants. Thorough evaluation requires continuing communication with participating customers.

J.6.4 Facility Evaluation Reports

The twelve facility evaluation reports have been drafted, or are in the process of are being prepared for each of the sub-metered facilities and they each cover up to three curtailment events as determined by the number of DR events, if monitoring equipment was installed in time to capture the events, and whether or not the participants' responded to them. The following provides a general outline of the Facility Evaluation Reports:

1) Utility & Program
   a. Customer / Site Description (location, meter ID)
   b. Site Function & Operations
   c. Site Size & Description
   d. Site Occupancy
   e. Notable Customer Attitudes Capabilities and Constraints Relevant to DR Programs

2) Expected Curtailment Strategy / Curtailed Loads
   a. Description of Expected Strategy
   b. List of Expected Loads (by building)

3) Sub-metering Strategy

4) Number Dates, Time and Conditions of Summer 2004 DR events

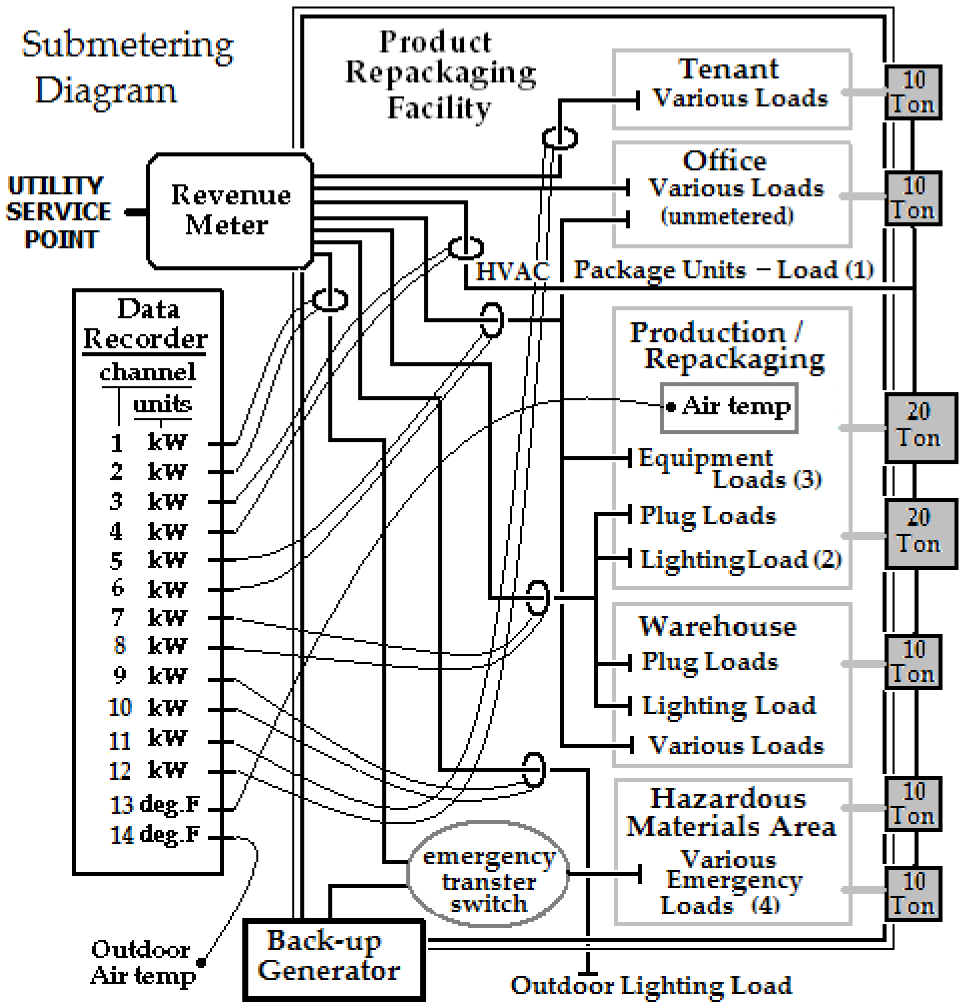
5) Analysis of Curtailment Performance (up to three events)

6) Key Findings / Lessons Learned

The reports attempt to be comprehensive in providing background information on participants, their DR strategy, the monitoring strategy, and all the attributes of the DR events that customers participate in. In each report the description of the monitoring strategy is accompanied by a simplified schematic drawing of the facility and monitoring points which serves as a reference to understanding the sequential exhibits (graphs) showing load curves as provided in the examples of Exhibits J-11 through J-14, above. An example of this schematic is shown in Exhibit J-15.

At the center of the evaluations are the load curve and impact analyses as described above and augmented by the findings of qualitative research. All graphic exhibits to the reports are grouped separately from report text, and cover a set number of individual load and temperature curves per the monitoring points (such as those diagramed in Exhibit J-15). Graphic exhibits are packaged by event, and appear in the same sequence for each event analyzed to facilitate comparison of event strategies and individual loads (and temperatures) between events.

Exhibit J-15
Example Schematic of Facility Loads and Monitoring Points



As will be explained in the following section of this report, the participants in the sub-metering sample fall into three groups differentiated by whether or not participants responded to DR events and if monitoring equipment was installed in time to capture data for the events of those that did respond. For each group the content of the Summer 2004 Facility Evaluation Reports varies, namely by the extent to which curtailment events are evaluated and presented. Where there were no events captured in 2004, only typical (weekly) load curves of monitored end uses are shown.

J.7 SUMMARY OF RESULTS FROM SUMMER 2004 SUB-METERING PARTICIPANTS

This section summarizes the results of each sub-metered site, grouped as follows:

Group 1: Participating Sites with Event(s) Captured by Sub-metering

Group 2: Participating Sites with Event(s) Not Captured by Sub-metering

Group 3: Non-Participating Sites

The focus of the discussion in this section will be on the first group, as the analyses conducted to date for this group best serve the objectives of the sub-metering evaluation for Summer 2004.

Only key attributes and summaries of curtailment strategies are presented for the sites in the second and third groups, as there were no curtailment events to analyze for these sub-metered sites. The preparation of background reports for these sites are under development.

J.7.1 Participating Sites with Event(s) Captured by Sub-metering

Exhibit J-16 lists the six sub-metering sites where one or more DR events were captured by installed monitoring equipment. The three sites enrolled in PG&E's CPP program were generally very active in their response to notifications, as these sites responded to all or most of the five DR events. In that all of PG&E's CPP five events occurred after the third week of August, sub-metering equipment was installed in time to capture all of these events at each site.

The two participants in SCE's DBP program responded to either one or two of the two events called for this program. In the case of the Multi-Building Office Complex #1, sub-metering equipment had not been installed to capture the participant's demand response to a June 9th event. The Multi-Building Office Complex #2 enrolled into the DRP program in late August. Sub-metering equipment was installed shortly thereafter and was in place in time to capture a 9/28/04 demand response test conducted by the facility and their Demand Reserves Provider, Onsite Energy, for their own testing purposes.

Each of these six sites are summarized in Exhibit J-16 and are described below, along with some of the key findings from their evaluations.

Exhibit J-16
Participating Sites with Event(s) Captured by Sub-metering

Customer	Utility	Program	Sub-metering Installation Date	Events in Summer 2004	Event Partic-ipation	Events Monitored
Product Repackaging Facility	PGE	CPP	7/30/2004	8/27/04 9/8/04 9/9/04 9/10/04 10/13/04	NO NO YES YES YES	NO NO YES YES YES
Agricultural Product Processing, Packing and Cold Storage Facility #1	PGE	CPP	6/11/2004	8/27/04 9/8/04 9/9/04 9/10/04 10/13/04	YES YES YES YES YES	YES YES YES YES YES
Baking and Frozen Storage Facility	PGE	CPP	6/24/2004	8/27/04 9/8/04 9/9/04 9/10/04 10/13/04	YES YES NO NO YES	YES YES NO NO YES
Agricultural Product Processing, Packing and Cold Storage Facility #2	SCE	DBP	5/28/2004	6/9/04 9/23/04	YES YES	YES YES
Multi-Building Office Complex #1	SCE	DBP	8/13/2004	6/9/04 9/23/04	YES YES	NO YES
Multi-Building Office Complex #2	SDGE	DRP	8/27/2004	9/28/2004 (facility test event)	YES	YES

J.7.1.1 Product Repackaging Facility

This facility was the sixth site to be sub-metered, and monitoring equipment was installed in time to capture all CPP events. Quantum has completed a draft report for this site that analyzes curtailment strategies for two of the three events in which this facility participated. The October 13th event has not been analyzed because revenue meter data has not been made not available for this event.

At this facility there are approximately XX,XXX total sq. ft. in one large building of which Approximately half of the floor area is conditioned floor space, including a seventh of the building's floor area that is tenant occupied. Approximately XX persons occupy the facility during normal operations which extend from 7:00 AM to 3:30 PM weekdays.

Product repackaging is the primary function of this site and repackaging specifications are determined by the participant's customers. A segment of production is operated on a just-in-time basis that may affect the participant's ability to respond to CPP event notifications.

HVAC and packaging equipment loads are the most significant loads at the facility, and electricity cost represent between 10% and 25% of the facility's total operating costs. The following list itemizes each of the process, lighting and HVAC loads that were planned for curtailment; each was monitored by sub-metering equipment.

1) (2) 20 ton HVAC package units (serving production/packaging area)
2) Lighting (in production/packaging area)
3) Production/Packaging equipment
4) Emergency Loads

Shedding the above loads is accomplished using manual operational changes. HVAC (1) and lighting loads (2) were primary in the customer's DR strategy and this was confirmed in the analysis of events. Production and packaging equipment loads (3) and emergency loads (4) were not considered by the customer to be high priority loads for responding to CPP events. The emergency loads (4) are served by a 160 kW emergency back-up generator that could be used in CPP events, but wasn't for any of the Summer 2004 events. All other loads listed were curtailed in all events in which the customer participated.

Beyond event impacts, key findings from the facility evaluation are as follows:

- Preparing for next-day curtailments required the customer to adjust production schedules and work shifts in advance. Personnel responsible for load shedding were either unavailable or too busy managing production to participate in the first two of five CPP events.
- The customer had some issues with the notification process and delays with bill credits. Minor occupancy comfort complaints were received during curtailment events though the site contact did not feel that complaints were significant and that there was any negative impact on employee productivity. The customer didn't utilize support from PG&E and did not know of the Technical Assistance Program (TAP), yet they expressed that they could have used assistance developing cost and bill savings estimates for some of their planned curtailment measures.
- The customer felt they had learned a great deal from their experience with DR events and were very well prepared to respond to events by summer's end. They were satisfied with their Summer 2004 bill savings and the CPP program overall, and they plan to continue participation in 2005.
- The effectiveness of HVAC load curtailment strategy was reduced by elevated outdoor air temperatures in that the measurement of HVAC curtailment at the whole-facility load is concealed by the combination of higher event-day outdoor air temperatures and mechanics of the standard three-day baseline load calculation. Equipment curtailment in this process facility was significant, though it proved to be a less reliable contributor to curtailment as measured at the revenue meter. Tenant loads can randomly contribute or detract from curtailment observed at the revenue meter.

J.7.1.2 Agricultural Product Processing, Packing and Cold Storage Facility #1:

This facility was the third site to be sub-metered, and monitoring equipment was installed in time to capture all five CPP events. Quantum has completed a draft report for this site that analyzes curtailment strategies for three of the five events.

This XXX,XXX sq. ft. agricultural product processing operation includes the sorting, quality control, washing, processing, packing, cold storage and of product. Normal plant processing operations occur between the hours of 6:00 AM and 2:30 PM on weekdays, and does not operate on weekends. Seasonal production varies as approximately 60% of the annual production occurs between the months of August to November. Approximately XXX persons occupy the facility during the peak season and of August through November. Occupancy is by a third during the off-season.

Central to the customer's DR strategy is the manual curtailment of cold storage systems for up to six hours in each of the three buildings. Curtailment of cold storage loads was only made possible because the type of stored agricultural products tolerate fairly wide, though short-lived temperature increases. At the time of the on-site survey, curtailment was expected in three of X total buildings, drawing from a menu of the following loads.

Building 1 – Main building

1) Reciprocation compressor (20 hp, cools 3,200 sq. ft.)
2) Two grinders (57 kW)
3) Three Packing machines (125 kW)
4) Lighting (6 kW – calculated)
5) Battery Chargers (3 kW)

Building 2 – Primary Cold Storage Building

6) Primary reciprocation compressor (75 hp, conditions 32,000 sq. ft.)
7) Secondary reciprocation compressor (60 hp, conditions 32,000 sq. ft.)
8) Condenser (10 hp)
9) (22) Evaporator fans (1 hp each)

Building 3 – Secondary Cold Storage Building

10) Reciprocation compressors (15 hp, conditions 7,200 sq. ft.)

Beyond event impacts, key findings from the facility evaluation are as follows:

- The customer indicated that they are very well prepared to participate in CPP events without significantly affecting operations. They found the notification process to be very effective. The manual control process was effective and easy for the customer to carry out as it only required less than one hour to initiate curtailments.

- The customer drew extensively from the above menu of curtailed loads for each event, though not all loads were curtailed for each event. The utilization of equipment loads for curtailment was reduced in later events. Cold storage loads were always included in curtailments, but not necessarily in all buildings. The customer did not exercise an option to pre-cool or ramp-up post curtailment loads beyond what response occurs from the normal thermostat controls.

- The customer did indicated that it would be useful to them to view their loads in real time and they would have found it beneficial to have had assistance from the utility regarding the use of their web-based monitoring system.

- Achieving bill savings and being a good corporate citizen were the customer's primary motivations for enrolling in the CPP program. Energy costs account for between 5% to 10% of their total cost of operations, yet they expressed that they are very concerned about their energy costs relative to other costs of production. The fact that equipment loads were curtailed for during the regular shift hours of the first event suggests that production schedules can be modified for the sake of energy savings.

- Overall, the customer was very satisfied with the program and they intend to continue to participate in 2005. However, they expressed less than complete satisfaction with the program tariffs, bill credits, and the duration of CPP events.

J.7.1.3 Baking and Frozen Storage Facility:

This facility was the fourth site to be sub-metered, and monitoring equipment was installed in time to capture all five CPP events. Quantum has completed a draft report for this site that analyzes curtailment strategies for two of three events in which this facility participated. Revenue meter data was not available for the third (October 13th) event.

Production schedules of this XXX,XXX total sq. ft. baking operation are constantly changing as they are determined largely by incoming product orders for a broad array of baking products. Normally, facility production occurs 22 hours each day between 4:00 AM and 2:00 AM, with hours between for facility cleaning. The three main sections of the single large building include a warehouse and freezing section, a mixing and baking area, and a smaller packaging area. 55 % of the building has conditioned floor space and company offices occupy about 10% of the total facility footprint. Approximately XXX persons occupy the facility during normal operations.

Depending on production circumstances at Caravan, the customer intends to manually shed several types of loads including refrigeration, HVAC, lighting and process loads. The total expected load curtailment potential during CPP events could exceed 200 kW. The following list itemizes the loads planned for curtailment at the time of the on-site survey:

1) (2) HVAC Chillers (60, 40 tons) serving the baking production area
2) (2) HVAC Chillers (20, 10 tons) serving the packaging area
3) Lighting panels in the central warehouse area (3.6 kW)
4) Lighting panels in the 2nd floor packaging area (8.6KW)
5) (4) freezer compressors (100 tons – total)
6) (2) Mixers (150 hp each)
7) (2) Battery chargers (10 kW*)

Chillers loads can be reduced serving HVAC systems in the baking production and packaging areas of the facility. The four chiller (compressor) loads (5) serving the freezer warehouse can also be shut off for up to 24 hours. Fluorescent lighting loads can be eliminated in areas where skylights are present, allowing operations to proceed normally. Often, facility staff will eliminate some or all of the overhead lighting during summer months because it isn't needed. The customer indicated a remote chance of shutting down a production line during a curtailment.

Beyond event impacts, key findings from the facility evaluation are as follows:

- During the two CPP events in which the customer participated, drops in the only curtailed loads included battery charger, compressors serving the freezer warehouse and one mixer. Revenue meter load curves show obvious curtailment in the beginning and end of the six hour curtailment period, but generally not during the middle three hours. The load curve analysis of the latter event showed greater demand savings.

- The customer indicated they were reasonably well prepared to participate in CPP events and they indicated that the notification process was very effective. However, the customer was unable to respond to two of five CPP events because the site contact was either unavailable or too busy managing production to participate. Missed notification, possible effects on production schedules and occupancy discomfort were stated as significant reasons for not participating in certain events.

- Although they indicated that they were much more knowledgeable about carrying out a DR strategy and implementing load sheds as a result of participation in the 2004 program, the customer was uncertain about future participation. In addition to concerns about possible effects on production schedules and occupancy comfort, the customer was also concerned about the perceived hassle and costs of operating a curtailment relative to current program incentives. Future participation in the program will depend on several possible changes to the program structure, though increases to program incentives will be likely be most influential.

- The customer was also disappointed to have encountered problems reviewing the prior day loads on utilities monitoring website. Being able to view loads would otherwise be very helpful in developing and modifying the customer's demand response strategy.

J.7.1.4 Agricultural Product Processing, Packing and Cold Storage Facility #2:

This facility was the first site to be sub-metered and it was very successful at executing its DR strategy for both of SCE's DBP events. As this facility was the first site to be sub-metered, both events were monitored and have been analyzed by Quantum.

The XXX,XXX sq. ft. facility is a citrus packing operation which includes the washing, packing and cold storage operations in three buildings; a fourth building is occupied by tenants. Normal processing operations occur during a 5:00 AM to 3:00 PM weekday work shift and approximately XX persons are on site during these hours.

The customer intends to manually shed multiple refrigeration and process loads in two of three buildings at the plant site. The total customer's expected load curtailment potential during DBP events could reach 650 kW, and DR measures could be maintained for up to 6 hrs. However, The customer did indicate that maintaining the peak level of load curtailment would be unlikely beyond a two-hour period. Temperatures in the cold storage rooms storage could be allowed to rise by up to 3 degrees per hour without experiencing spoilage, but it is assumed that this rise in temperature could not be tolerated for six hours.

The following list itemizes the menu of planned process and refrigeration loads that could be manually controlled during demand bid events:

Building 1 – Leased building, (no curtailment planned by tenant).

Building 2 – Cold Storage

1) 2 ammonia chillers (120 tons ea.; cooling 54,000 sq.ft.),
2) 2 Cooling tower fans

Building 3 – Front Office, Washing, Packaging & Cold Storage

3) 150* ton chiller for cold storage
4) 320* ton chiller for cold storage
5) 1 Air compressor
6) 4 CW pumps
7) Forklift charger basement room 100
8) 1 Air Handlers serving 1st floor room
9) 4 water (lemon washing) water pumps
10) Product Grading equipment
11) Storage conveyor
12) Carton former/Conveyor
13) FMC dryer
14) Palletizer

Due to site constraints on installation of sub-metering equipment, the metering plan called for sub-metering only in Building 3, covering loads (3) through (15). Beyond event impacts, key findings from the facility evaluation are as follows:

- During first of two DBP events the staff at the site conservatively bid a 100 kW reduction, but achieved reductions that more than tripled the bid loads during the 3 pm to 7:00 PM event, and accounting for roughly 50% of the total whole-premise load. The customer explained that they wanted to try to obtain as much demand reduction as possible as a test of their DR strategy. The customer initiated the curtailment approximately four hours prior to start of the event period.

- The load drop of the cold storage systems in building 2 was not directly monitored. Whole facility loads indicate that the largest contribution to the facility curtailment came from this building. However, more interesting load shedding behavior was observed in Building 3 as a smaller chiller (3) was run at a reduced capacity during the curtailment, and was switched off at the end of the event period; the larger chiller (4) was off for the duration of the event, but was brought up to normal operation immediately after the event terminated.

- Both whole-facility loads and measured demand savings in second event were significantly reduced by comparison to the first. Building 2 cold storage systems were likely not curtailed at all during this event.

- The customer reported being very satisfied with PG&E'S DBP program and they were very likely to continue bid in future events.

- The customer would have liked assistance with understanding the mechanics of the programs baseline calculations

J.7.1.5 Multi-Building Office Complex #1:

This facility was the eighth site to be sub-metered, and installation of monitoring equipment was completed on 8/13/04. Analysis of one DR event at this site and preparation of a facility evaluation report are underway but have not been completed to date.

The site is an excellent addition to the sub-metering sample as it is one of two sites that deploys an automated DR strategy by use of a three-tiered pre-programmed load shedding sequence within their energy management control system (EMCS). The energy information system (EIS) components of the site provide an excellent an exceptional opportunity to collect interval data from a large number of monitoring points.

The customer site is a six-building, multi-tenant office campus and restaurant complex totaling X,XXX,XXX sq. ft. of conditioned floor space. The two primary office buildings on the campus each accounts for approximately XXX,XXX sq. ft. of floor space on XX floors and the facility twice curtailed loads in Summer 2004. All buildings on the campus are owned by this corporate customer and include three smaller buildings housing restaurant tenants, a large separate parking structure serving the campus, and a separate structure for the campus central plant. Total per building occupancy the two buildings is not known.

All major energy HVAC and lighting systems are served by a Siemens EMCS. Space temperature set points are set by the EMCS to 72 to 74 degrees F during normal building operations which extend from 8:00 AM - 6:00 PM weekdays, and between 8:00 AM - 1:00 PM on Saturdays. The facility also has real-time metering, a sophisticated communications infrastructure and internet access to their online energy information system (EIS) component. The EIS component is central to the sub-metering strategy for the site, as it is used for trending and analyzing 15-minute interval data at the revenue meter level as well as for a large number of demand, consumption, temperature and flow parameters used to track building operations during normal conditions and during curtailments.

The customer's curtailment strategy is fully planned and programmed into the site EMCS. Three different levels of demand response are activated by slowing variable speed drives (VSD) on the fans within designated Air Handling Units (AHU) by 40%, 60% or 80%. While this three-tiered strategy only directly controls AHU loads, two large-capacity chillers (1400 tons total) and other related central plant loads are affected by the curtailment strategy.

The central plant houses two centrifugal chillers; one has a capacity of 850 tons and the second at 550 tons. There are two cooling towers at the central plant and a total of 38 air handling units throughout Buildings 1 and 2, each assigned to a separate floor. A 1.0 MW standby cogeneration plant was installed at this facility two years ago.

Other notable information about the site and its energy management personnel include the following:

- Although the customer's primary curtailment strategy was to control AHU fan speeds, the loads curtailed on the September 23rd (captured) DBP event only included common area lighting and outdoor fountain pump loads. These loads were not monitored as they were considered to be ancillary to the curtailment of AHU loads.

- The primary contact at the customer site indicated that they were somewhat dissatisfied with their summer 2004 participation, but became more knowledgeable about operating curtailments. Driven by the primary motivation to reduce energy costs, the customer is very likely to participate in future DBP events and they expect their demand response capabilities to increase.

- The primary customer contact reported that an hour is adequate time for executing a curtailment following receipt of event notification; the customer reported both summer 2004 events were same-day events. The contact who activates curtailments also reported that the notification process was somewhat ineffective in that the notification process was thought to be limited to sending messages to only one individual at the site who was often out of his office or out of town. In making recommendations for improvements, the customer said SCE could improve the notification process by developing options to send notifications to different designated individuals within the organization.

J.7.1.6 Multi-Building Office Complex #2:

This facility was the eleventh site to be sub-metered, and monitoring equipment was installed in time to capture a customer's own facility curtailment test on 9/28/04. Quantum is preparing a facility sub-metering evaluation report that describes the customer's curtailment strategy, and provides an analysis of the 9/28 test event. The facility changed ownership in early October and it is uncertain whether this facility will continue as a site within the sub-metering sample.

This customer is the only sampled site enrolled in the DRP Program. The customer was enrolled in the DRP program in late September by Onsite Energy, a designated Demand Reserves Provider for the DRP Program. Onsite has a long-standing relationship to the customer as an energy services provider and they were contracted to enroll this customer in the DRP Program, define a DR strategy with the customer, and provide various sub-metering-related services. The 9/28 test curtailment was jointly planned by Onsite Energy and the

Built in 1990, the customer site includes a garage and central plant facility and a 16-story office building comprised of XXX,XXX sq. ft of leaseable office area. The majority of the building tenants are professional firms and building occupancy is typical of an office building: 6 AM to 6 PM Monday through Friday and one-half day on Saturdays.

All major energy HVAC and lighting systems are served by a site EMCS. The facility has the real-time metering, communications infrastructure and internet access available for analysis of their electric utility meter 15-minute interval data, yet only a few monitoring points within the buildings are trended for analytical and historical purposes.

Boiler and chiller plant operation is based on outside air temperature and return water temperature, and space temperature set points are adjusted by time of day and day of week. Lighting controls are programmed to switch off common area lighting outside of business hours and occupancy sensors are located throughout in most of the tenant office areas. The energy management system features a load-shedding capability for lighting loads. There is also a 125 kW diesel backup generator at the site.

A 2002 report prepared by Onsite Energy for the customer previously identified possible components to a demand response strategy include cumulative chiller demand limiting, temperature resets, and lighting setbacks. The possible demand reduction was estimated to be 50 kW.

A newer DR strategy to obtain 101 kW of demand savings was devised for the customer's participation in the DRP program. This newer strategy contains the following components:

Central Plant:

1) Reset chilled water setpoint by 3 to 5 degrees (F)
2) Turn off condenser water pump

Office Tower:

3) Set supply air fans to minimum speed in seven AHUs (serving 7 of 16 floors)
4) Disable freight elevators
5) Turn off common area lighting on unoccupied floors 4, 7 and 8

The 9/28 test curtailment was jointly planned and executed by Onsite Energy and the facility energy manager; analysis of this test event has not been completed.

J.7.2 Participating Sites with Event(s) Not Captured by Sub-metering

This section provides a very brief summary of the sub-metering project status for sites where participation in DR events was not captured because monitoring equipment was not in place in time to record the event. Exhibit J-17 lists these three sites and provides detail on the dates of DR events, those that the customer responded to, and the completion date of the installed monitoring equipment.

J.7.2.1 Multi-Building Office Complex #3:

This facility was the seventh site to be sub-metered, and monitoring equipment was installed in time to capture the latter of two DBP events called. However, this facility only participated in the first (uncaptured) event. Quantum will prepare a short report that details the customer's curtailment strategy, the sub-metering installation and examines non-curtailed sub-metered loads.

This XXX,XXX sq. ft. facility consists of two leased office buildings, one with X and the other with Y. Standard operating hours are 8:00 AM to 6:00 PM weekdays and 9:00 AM to 1:00 PM on Saturdays. There are approximately XXX occupants in both buildings.

Exhibit J-17
Participating Sites with Event(s) Not Captured by Sub-metering

Customer	Utility	Program	Submetering Installation Date	Events in Summer 2004	Event Partic-ipation
Multi-Building Office Complex #3	SCE	DBP	7/31/2004	6/9/04 9/23/04	YES NO
Office Building and Call Center	SDGE	DBP	8/26/04 installation 9/23/04 data capability	5/03/04 6/30/04 9/7/04	NO YES NO
University Campus	SCE	DBP	Not completed	6/9/04 9/23/04	YES NO

The HVAC system consists of a single central plant serving both buildings. A Siemens EMS is in place to control HVAC load, but it is not set up to control lighting systems. Lights are controlled with time clocks located in the electrical closets on each floor. The zone controls for each floor's AHUs are pneumatic, so the EMS system cannot be used to trend space temperatures. The AHUs themselves originally had pneumatic controls, but have been retrofitted with digital controls of the AHUs.

The customer's planned DR Strategy includes starting both chillers early on a demand-bidding day and then shutting one off at 4:00 PM. AHU fans will be affected by this plan since they are variable air volume (VAV) fans. When one chiller is shut off, the supply air temperature is expected to rise, causing space temperatures to rise, and causing VAV terminals to open. The AHU supply fan will speed up to maintain static pressure at the increased flow.

The customer indicated that they are very well prepared to respond to notification, as load curtailment at this site is mostly automated and it takes an hour or less to carry out most of the planned HVAC measures. They customer also plans to shut off some lighting circuits for common areas although these are controlled manually. The customer does not plan to enlist tenant participation in their curtailment strategy, and the facility manager expressed concern about impacting tenants during curtailment.

The customer reported that they were unable to attain the minimum demand bid requirements of 100 kW during the first DR event. Members of the Quantum team have worked with the customer to explore means of shedding load to reach this minimum requirement. The customer did not participate in the latter of two events called because they claimed a notification was never received, although this may have occurred due to a change of energy management personnel in June.

J.7.2.2 Office Building and Call Center:

This facility was Quantum's ninth site to receive sub-metering equipment, yet due to delays with a customer-supplied phone line, installed metering equipment could not capture the last event of three events on 9/7. However, this customer only participated in the 6/30/04 event. Quantum will prepare a short report that describes the customer's curtailment strategy, the sub-metering installation and examines non-curtailed sub-metered loads.

This XXX,XXX sq. ft. facility houses corporate offices and a call center with a typical weekday occupancy of XXXX; at times occupancy increases by 50%. The energy manager at this facility intends to shed cooling loads from rooftop package units (RTU) as well as lighting loads.

J.7.2.3 University Campus:

This university campus facility is the last site to sub-metered for 2004. Although components of the monitoring equipment were installed as early as mid-July, the programming of monitoring equipment has yet to be finalized. The monitoring equipment system at this site is of the second metering option as described in Section J.3.4.1, and when completed, the data monitoring capabilities at this site will nearly cover the entire university campus.

Customer tasks that are needed for completion of the sub-metering project have delayed completion of the installation. Quantum will prepare a report that describes the customer's curtailment strategy, the sub-metering installation and examines non-curtailed sub-metered loads. This report will also describe installed sub-metering capabilities to be completed by summer 2005.

The campus is a modern, XXX,XXX sq.ft. private university with an annual utility bill of around one million dollars and a summertime demand of around one megawatt. The campus is largely vacant during the second half of May, June and July, and the first half of August. The customer only responded to a June 9th DBP program event, as they reported to be too busy with aspects of a returning student population to respond to a September 23rd DBNP event. .

The primary component of the campus DR strategy is to reduce setpoints of most of the campus's air handler variable frequency drives (VFD's) to achieve a power reduction of approximately 60 to 70%, or 313.5 kW. This DR strategy would be implemented as a campus-wide event automated by the master controller of the Campus EMCS.

The facility manager stated that it was also acceptable to reprogramming the EMS to raise space temperature setpoints from the normal degrees to 78 degrees (F). The chiller kW demand savings from this measure is expected to be 67 kW.

The campus has several water fountain, filter and pool pumps on VFD's that are controlled by lighting panels in three separate buildings; these pumps are excellent candidates for a DR strategy though curtailment would require a person visiting three buildings separated by a total distance of approximately 300 yards.

J.7.3 Non-Participating Sites

This section provides a very brief summary of the sub-metering project status for sites that didn't participate in any Summer 2004 DR Events. Exhibit J-18 lists these three sites and provides dates of DR events and completion of the sub-metering installation.

Exhibit J-18
Non-Participating Sites

Customer	Utility	Program	Submetering Installation Date	Events in 2004
Glass Processing Facility	SCE	DBP	7/12/2004	6/9/04 9/23/04
Corporate Office and Laboratory	PGE	DBP	8/28/2004	7/26/04
Food Production and Frozen Storage Facility	PGE	DBP	6/1/2004	7/26/04

J.7.3.1 Glass Processing Facility:

This facility was the fifth site to be sub-metered, and monitoring equipment was installed in time to capture the latter of two DBP events called by SCE. However, This facility did not participate in either event. Quantum will prepare a short report that describes the customer's curtailment strategy, the sub-metering installation and examines non-curtailed sub-metered loads.

The customer's chemical processing site includes twelve buildings, although occupancy at the site during normal operations is only XX persons.

Components of the customer's planned DR Strategy include shutting down a cooling tower fan, air compressors, glass transfer equipment motors, dissolver operations, various conveyors, mixers, fans and tank farm pumps.

Participation in one possible Summer 2004 DR event did not occur because the facility manager was too busy with production. However, the customer's facility manager stated that if he is around at the time of future event notifications, they are very likely to participate; the time needed to respond to a notification is an hour or less.

J.7.3.2 Corporate Office and Laboratory:

This facility was the tenth site to receive sub-metering equipment. Due to delays with a customer-supplied phone line, was incapable of capturing meter data until mid-September. Regardless, metering equipment would not have been in place to capture the only DBP event called by PG&E on 7/26/04. Though somewhat uncertain, it has been concluded that the customer did not participate in this event. Quantum will prepare a short report that describes the customer's curtailment strategy, the sub-metering installation and examines non-curtailed sub-metered loads.

The customer site includes XXX,XXX sq. ft. in three buildings which pharmaceutical product research laboratories and corporate offices. The site is known to have Siemens and Trane controls on their HVAC systems .

Components of the customer's planned DR Strategy include duty cycling of two AHUs in each of two buildings. Two make-up air fans will also be cycled in the second building. These measures are expected to reduce loads on one of two of the facility's chillers, and the combined load reduction is expected to be as high as 280 kW.

J.7.3.3 Food Production and Frozen Storage Facility:

This facility was the second site to be sub-metered, and monitoring equipment was installed in time to capture a 7/26 event. Quantum's preliminary analysis suggests a load curtailment in the four hours prior to the 4:00 to 6:00 PM event.

This XX,XXX sq. ft. food processing and frozen storage facility operates multiple weekday shifts between 4:00 AM and midnight. Occupancy is typically 160 persons during work shifts, although summer manufacturing sometimes requires increases in occupancy of 30%.

The primary component of the customer's planned DR Strategy includes shutting off four compressors serving the frozen storage areas. The freezer system is known to maintain adequate storage temperatures for up to 48 hours as long as freezer doors remain closed. Other possible process loads slated for curtailment include the following:

1) (6) Glycol Pumps
2) (7) evaporator fans
3) battery charges
4) Spiral freezers

Curtailment of freezer and process loads are expected to result in demand reductions of up to 500 kW and 60 kW, respectively.

The customer did not participate in the only possible DBP event of Summer 2004 because they did not want to interrupt production. The customer reported that day-of event notifications are nearly impossible to respond to. The customer's participation in the DBP program for 2005 is uncertain.

J.8 SUB-METERING RECRUITMENT AND PARTICIPATION-RELATED FINDINGS

Because analysis of the sub-metering data is still in progress, current findings and lessons learned are primarily drawn from experiences gained in the process of candidate recruitment and data collection. Lessons learned from the individual site analyses will be synthesized after all of the site reports are complete.

Re-examination of the salient experiences with the recruitment and data collection process provides an opportunity to assess what worked well and what did not. The discussion in this section highlights how findings from the recruitment and data collection process revealed important attributes of the program participant population. There is wealth of information about demand response behavior both within the sample of 12 sub-metered sites and for the many participants that were contacted during recruitment for sub-metering.

The remainder of this section presents experiences gained during the candidate recruitment process, the relationship between the screening criteria applied and the resulting sample, and a retrospective assessment of the effectiveness of the 2004 metering data collection and analysis in meeting the established sub-metering evaluation objectives.

Several challenges, most of them expected, were encountered in the customer recruitment and data collection process, which all affected the completion rate of sub-metering installations and the ability to collect interval data.

- The recruitment process involved significant management resources for reasons related to participant screening for suitability and the large average number of customer contacts needed to navigate a given candidate through the recruitment, research, installation and data collection process.

- Site contacts were too often not engaged or were otherwise restricted in their ability to participate in the DR programs that they had signed up for. Too often participants were unfamiliar with the program requirements, and had not been provided ample opportunity to assess the ability of their site to participate in DR events, not to mention how few had established a clear DR plan. Consequently, contacted customers were often limited in their ability to consider hosting a sub-metering project, or to engage in a discussion of possible program or sub-metering benefits and costs. For these reasons, normal metering recruitment "tools" often could not be applied, such as explaining the value of sub-metering to help plan a particular customers demand response.

A retrospective examination of the screening criteria applied and the outcomes of recruitment efforts is summarized below:

1. **Customers that are highly likely to opt-in for DR events**. This screen was applied as a pass-fail criterion, based on expected probability of demand response. The sample outcome was 9 of 12 sub-metered sites did participate in summer 2004 events. Any future metering efforts should continue to emphasize this most important screen, in an effort to reduce the likelihood that metering points might fail to participate in DR events.

2. **Customers that will shed multiple loads at a site**. Due to the expense of metering, the plan to emphasize sites with multiple load shed objectives paid-off enormously.

Furthermore, the emphasis on building "experiences" with energy system "services" (such as internal building temperature where cooling systems are being shed) is a worthwhile objective to include and prioritize in future metering efforts.

3. **A mix of business types and customer sizes across the metering sites**. A sample was sought that covers a representative range of business types and customers sizes. The sub-metering sample was a well-diversified sample, consisting of a representative distribution of participants across program, utility and business types.

   Similarly, the resulting sample includes a diverse range in the level of sophistication of demand response automation. Site-by-site methods ranged from manual control of sub-systems to fully automated touch-of-the-button DR strategies.

4. **A mix of end uses and shed strategies across the metering sites**. The variety of end uses and shed strategies included in the sample provides enhanced sample value. At the same time, the sub-metered loads are very typical of the type of loads found throughout the participant population; captured loads are not particularly unusual.

5. **Ability to cost-effectively sub-meter loads and energy services of interest.** In general, cost-effective and reliable methods were used to retrieve sub-metering data. Synergistic recorders, using a phone line for data downloads, proved the best option for most sites. While more in-depth monitoring is possible using "N Box" and EMS trending methods, N Boxes are much more costly and time consuming to implement and EMS trending is less reliable and at the mercy of participant willingness and systems. Thus greater overall control of the data stream and timeline was achieved using the methods selected. This more traditional load research method removes considerable "human factor" issues from the installation and data collection processes and procedures.

   In all but three of the twelve sampled sites, metering plans called for the use of the simplest sub-metering data collection option, recorder installation. These proved to be reliable sub-metering options that could be installed efficiently relative to other alternatives, partly due to the fact that there was a greater resource of technicians skilled at installing this system relative to the other types of systems. Very in-depth "N Box" installations are of the opposite extreme, being highly complex, slow to install, and require not only a specifically skilled technician to install but also much greater levels of cooperation and coordination with the affected participant. However, once installed, these systems feature extensive monitoring capabilities

   While our preference is for sites that provide direct access to the data using a telephone line, three out of the twelve sites include alternate data collection strategies; data retrieval relies instead on the host participant to periodically send interval data. In all such instances a successful process was put in place to obtain those data on a regular basis; institutional agreements in this process worked well.

The restricted pace of recruitment combined with the uncertainty surrounding when and how many DR program events would be called, led to situations where monitoring equipment was not installed in time to capture curtailment actions. This occurred at three of the twelve sub-metered sites where the customer chose to respond to only one of the two or three curtailment events; in each case the event in which these customers participated occurred before July.

- Compounding this was the fact that the response rates to DR notification for these sites was 50% or less, thus lowering the probability of data capture.

- Furthermore, relative to the other sample points, these sites had fewer DR events that they were able to respond to – that is, fewer DR events were called.

A third group of three additional participants, despite being selected for sub-metering on the assumption of a high probability of participation, did not participate at all in Summer 2004 DR events. In retrospect, little more could have been done in the metering recruitment screening process to eliminate these three customers. That particular screen was given the greatest level of importance and participants were subject to the greatest level of scrutiny in compliance with that screen.

Given the relatively high participation figures of SCE and the many successes in sub-metering recruitment from SCE's DBP program, it was challenging to stratify the sub-metering sample by utility and by program. Still, the results were very successful in achieving those goals.

On-site surveys were a pivotal step in determining eligibility of sub-metering candidates and understanding trade-offs between different sub-metering approaches for a given site. On-site surveys were more of a cost control point than metering installation in terms balancing costs and the quality and extent of data to be obtained from a site.

In general, impacts and load curve analysis of captured DR events allows for a depth of understanding about DR behavior for sampled sites that is otherwise unattainable. The combination of examining load curves supplemented by qualitative research goes far in telling a curtailment story, whether a story of what happens to curtailed end uses and related electric system "services" (such as building cooling) or one of institutional disposition and behavior. These stories compliment knowledge of participant populations well beyond what can be achieved using empirical whole building impact methods, like those presented in other Chapters of this report.

APPENDIX K
SUBMETERING RECRUITMENT AND DATA COLLECTION DOCUMENTS

APPENDIX K
SUBMETERING RECRUITMENT AND DATA COLLECTION DOCUMENTS

The collection of documents contained in Appendix K are those that supported the Candidate Recruitment and Data Collection Process as discussed in different sections of Appendix J. Each of these documents were important tools used in one or more of the steps to the process that yielded a well-stratified sample of twelve submetering sites for the summer 2004 submetering evaluation. These documents of Appendix K include the following:

1. Recruitment Documents:
   - K.1 Recruitment Guide, (telephone script),
   - K.2 Customer Referral Letter (template)
   - K.3 Monitoring Agreement (template)

2. Data Collection Documents:
   - K.4 Onsite Data Collection Form
   - K.5 Data Point Summary Form

APPENDIX K.1
RECRUITMENT GUIDE

(Telephone Script for Submetering Candidates)

INTRODUCTION

Hello. My name is <NAME> calling from Quantum Consulting, on behalf the California Public Utilities Commission and <IOU>. This is not a sales call; we are calling about your participation in <IOU's> <Critical Peak Pricing or Demand Bidding or Hourly Pricing Option> Program. We would like to ask you some questions to see if you are eligible to participate in an evaluation research study. The purpose of this research is to determine the energy savings and customer impacts that result from customers' load reduction activities under one of <IOU's> new Demand Response Programs.

If utility contact information requested, please use the following:

SCE:	Edward Lovelace	(626) 302-1697
PG&E:	Susan McNicoll	(415) 973-7404
SDG&E:	Leslie Willoughby	(858) 654-1262

[IF RESPONDENT IS NOT AWARE OF PROGRAMS] <IOU's> records show that you are a participant in the <CPP/DBP/HPO> program.

1) Find out if they are the best person to talk to about their company's participation in the CPP or DBP program?
   - If No, find out who in the company is the most knowledgeable about their participation in these programs.
     - Contact Name
     - Contact Number
     - Good time to reach Contact

2) Verify the correctness of our data.
   - They are signed up for <DBP/CPP>.
   - For CPP Participants only: They <ARE/ARE NOT> signed up for the Bill Protection Plan.
   - They <ARE/ARE NOT> signed up for the Technical Assistance Incentive.
   - The address of the facility that is enrolled.
   - [FOR MULTIPLE FACILITIES] The address of the facility we are interested in.

3) Inform customer about the following:

- The objective of the research study is to measure the impact of a customer's load reduction activities under one of the new Demand Response programs.
- The results of this research will be used to improve California's Demand Response programs and to aid customers in determining optimal load reduction strategies that will allow them to take part in these new programs.
- Participation in this study is only available to customers who have signed up for one of these two Demand Response programs.
- Participation in this study will require Engineers from Quantum Consulting or its subcontractors to install monitoring equipment at their facility that will allow data to be captured on both the energy usage and facility effects during the load reduction periods.

4) [ONLY READ IF ASKED ABOUT THE BENEFITS OF PARTICIPATING IN THIS STUDY:]

The benefits of participating in this study are:

1. Assistance in determining the best load reduction strategies for their facilities.
2. If interested, input into the scope of the monitoring plan and analysis.
3. Review of the analysis of the monitoring data for their facility.
4. Contribution to improvements in the reliability and cost-effectiveness of California electricity system.

5) IF NECESSARY] DISCUSS POSSIBLE RECEIPT OF THE MONITORING DATA ITSELF. [DO NOT PROMISE REAL-TIME OR SPECIFIC ACCESS TO THE DATA OR A SPECIFIC SCHEDULE FOR RECEIPT. MONITORING DATA MUST PASS OUR QUALITY CONTROL ANALYSIS AND BE USED IN THE EVALUATION].

6) [ONLY READ IF ASKED ABOUT WHAT TYPE OF MONITORING WILL BE INVOLVED:] WE HAVE THREE GENERAL MONITORING STRATEGIES FOR THIS RESEARCH PROJECT, ONE OF WHICH, OR A COMBINATION OF WHICH, WOULD BE EMPLOYED AT YOUR SITE. THESE STRATEGIES ARE:

*1. Existing EMCS***.** In this approach, the facility's existing EMCS is used to collect time-series data and make it available for access over telephone or Internet connections.

2. Parallel System (Gateway). In this approach, an additional monitoring system is installed in parallel with the existing energy management and control system (EMCS), and provides separate on-site storage and communication capability.

3. Independent Monitoring (logger- or recorder-based system). In this approach, all equipment needed to facilitate measurement and data collection is installed, using either loggers or monitoring recorders. This includes the installation of CT's, sensors and flow meters.

5) Ask the following questions about their facility:
   - What is the main business activity at their facility?
   - Do they have a back-up generator for their facility?

6) Ask about their current curtailment plans for participating in the <DBP or CPP> program.
   - For DBP: What is their likelihood of entering a bid?
   - For CPP: What is their likelihood of shedding load during an event?
   - Confirm their current maximum/average summer load? <WE HAVE THIS>
   - What percentage of their average summer load do they anticipate being able to shed during an event?
   - If they stated they had a back-up generator above: Do they plan to use the back-up generator during their load reduction? If so, what percentage of their reduced load do they plan to cover using their back-up generator?
   - What components of their operation do they plan to involve in their reduction? Specify equipment and general location.

[IF MULTIPLE ACTIONS, ASK FOR DR COMPONENT 1 THROUGH N]

   - What is the approximate capacity of this equipment?
   - Roughly what percentage of load on each piece of equipment specified do they plan to shed?

[END LOOP]

   - Are there any additional specific actions they may take under a critical load event?
   - What concerns do they have about entering a bid?
   - What concerns to they have about shedding load?

7) What type of monitoring equipment do they currently have installed?
   - EMCS System, PLC's (Programmable Logic Controllers), Other?
   - What types of equipment are connected to these systems? [HIGH LEVEL, GENERALLY]

8) For customer who may be qualified based on their answers to the questions above, determine if they would be interested in participating in this measurement project.

[IF NECESSARY] Discuss possible receipt of the monitoring data itself. [DO NOT PROMISE REAL-TIME OR SPECIFIC ACCESS TO THE DATA OR A SPECIFIC SCHEDULE FOR

RECEIPT. MONITORING DATA MUST PASS OUR QUALITY CONTROL ANALYSIS AND BE USED IN THE EVALUATION].

9) If yes, explain next steps:

- Fax them a utility referral letter.
- Schedule a site visit by one of our Engineer's who will determine the appropriate metering plan. [IF NECESSARY DESCRIBE THE DIFFERENT METERING STRATEGIES (above)]
- Determine who at the facility the Engineer should contact to schedule this site visit. Get name and Number.
- Sign an agreement form to confirm participation in this evaluation.
- Schedule an appointment to have the monitoring equipment installed.

10) If unsure, explain or re-explain the benefits of participating in this study

CLOSING

Thank you very much for helping the CPUC and <IOU> with this important evaluation project. If you have any additional questions surrounding this metering effort, please give me a call at 510-540-7200.

APPENDIX K.2
CUSTOMER REFERAL LETTER

(Template)

Mr. /Mrs. /Ms. <Contact Name>
<Company Name>

<DATE>

Dear Mr. /Mrs. /Ms. <Contact Name> :

We hope that we can count on you to participate in the SCE Demand Response (DR) program evaluation. SCE is conducting this evaluation of its DR programs, as required by the California Public Utilities Commission (CPUC). As part of the evaluation we wish to monitor a sample of the installed sites to better understand the relationship between the electric system impacts of DR programs and any customer effects (such as customer comfort, productivity, etc.) Understanding these changes will help to enhance the programs and lead to improved information, methods, and tools to facilitate demand response participation, maximize customer benefits, and reduce or eliminate any undesirable customer impacts.

Quantum Consulting has been retained by SCE to conduct this evaluation. The monitoring effort will likely include measuring the usage of equipment impacted by demand response actions, as well as, in some cases, measuring the associated energy services provided by that equipment (e.g., lighting levels, indoor temperatures, air movement, etc.). Any mechanical and electrical contractors will work under the direct supervision of a Quantum Consulting technician. No equipment shutdowns are required and no alteration in your operation is anticipated. Attached is a copy of the Monitoring Agreement you would be asked to sign, if you agree to participate in this program evaluation.

We would like to begin by having one of our technicians visit your site for the purpose of recording relevant information on your facility. Our installations are planned to take place in May and June this year.

If you have any questions on the program please feel free to contact me at 510-540-7200. Thank you again for your consideration of participation in this important evaluation.

Sincerely yours,

John Bidwell
Quantum Consulting

JB:jb

APPENDIX K.3
MONITORING AGREEMENT

(Template)

This agreement is made on this ___ day of ______, 2004, by and between Quantum Consulting, of 2001 Addison Street, Suite 300, Berkeley, California and ___________________________ (Utility Customer).

Quantum Consulting under contract with (Utility) desires to install electric load monitoring equipment, related devices and component parts (Equipment) in the facility located at ____ (Facility).

Quantum Consulting agrees to install the monitoring Equipment in the Facility for the "Demand Response" program evaluation. Furthermore, Quantum Consulting and the Utility Customer agree to the following terms and conditions:

1. Utility Customer agrees to allow Quantum Consulting, or its subcontractor, access to the Facility to install Equipment, collect data from Equipment during normal business working hours or upon prior mutually agreeable arrangement during non-business working hours. Utility Customer agrees to allow Quantum Consulting reasonable access to the Facility for the installation, inspection, maintenance and removal of the special metering equipment as well as to collect site information related to the monitoring activities.

2. Quantum Consulting and Utility Customer will agree to a mutually convenient installation schedule of the Equipment. Quantum Consulting reserves the right to drop the Facility from the monitoring program If further investigation reveals sufficient data will not be obtained.

3. Quantum Consulting agrees to provide Utility Customer with results of the monitoring that has taken place at the Facility after our analysis is complete.

4. Utility Customer agrees to contact Quantum Consulting if condition of the Facility changes after the Equipment has been installed that will alter energy use or energy use patterns. Quantum Consulting can be contacted by phone at (800) 599-4671 Monday through Friday from 8:30 a.m. to 5:30 p.m. Pacific time.

5. Utility Customer agrees not to tamper with the Equipment or interfere with the collection of reliable data.

6. Utility Customer will not be responsible for costs associated with installation or removal of the monitoring Equipment.

7. Quantum Consulting, or its subcontractor, agrees to remove Equipment after completion of the study and return the area of the Facility where the Equipment was installed to the condition it was in prior to the installation by Quantum Consulting or its subcontractors. The date of Equipment removal will be no later than December 31, 2005.

8. Quantum Consulting is the sole owner of the Equipment and such Equipment shall not be deemed to be a fixture of the Facility.

9. Utility Customer agrees to participate in interviews related to demand response events, actions, and facility effects.

IMPORTANT:

I accept that this Agreement is subject to the conditions of, and not in conflict with, any other outstanding agreement between Quantum Consulting and Utility Customer. Except for otherwise expressly provided for herein, this Agreement may be changed, waived, discharged or terminated only by an instrument in writing, signed by the party against which enforcement of such change, waiver, discharge or termination is sought.

If you agree to participate in the survey, [UTILITY] and Quantum Consulting will provide energy use, load information, and survey responses for your facility to the Study Team (the California Energy Commission, its contractors, and [UTILITY]). The use of the data from your facility will be limited to further "Demand Response" program evaluation and/or academic research. Except as provided above, this information and the information collected during the survey will not be released in a form that includes the identification of any business, individual or facility.

Please contact Kris Bradley, Project Coordinator, at (510) 540-7200 should you have any questions or concerns.

Accepted as of the above date by:

______________________________	Quantum Consulting
(Customer)	
______________________________	______________________________
(Business Representative Signature)	(Quantum Consulting Signature)
______________________________	______________________________
(Printed Representative Name)	(Printed Quantum Consulting Name)
Mailing Address:	
______________________________	2001 Addison Street, Suite 300
______________________________	Berkeley, CA 94704
______________________________	(510) 540-7200

[QUANTUM FACILITY TRACKING NUMBER]

APPENDIX K.4
ONSITE DATA COLLECTION FORM

Attached on the following pages is the Onsite Data Collection Form.

DEMAND RESPONSE EVALUATION PROJECT
COMMERCIAL/INDUSTRIAL FACILITIES
ON-SITE DATA COLLECTION FORM
(05/20/2004 version)

I. INTERVIEW INFORMATION

Interviewer: ______________________

Date of Interview: ______________________

Facility: ______________________

Street Address: ______________________

City: ______________________

State: ______________________

Zip: ______________________

Interviewee Name: ______________________

Title: ______________________

Phone: (   )   -

Electric Utility Serving Facility ______________________

Number of meters serving this facility ______________________

II. DESCRIPTION OF FACILITY

A. Business Characteristics

1. Primary Services or Products
   a. ______________________
   b. ______________________

   SIC codes (4-digit) for primary services: | | | | | | | | | |

2. Secondary Services or Products
   a. ______________________
   b. ______________________

   SIC codes (4-digit) for secondary services: | | | | | | | | | |

B. Facility Characteristics

a. Total floorspace of this facility ______________________ ft^2

b. Conditioned floorspace (this facility) ______________________ ft^2

C. Occupancy Characteristics

Indicate the daily schedules of operation for this facility:

Day Type	Business Hours (*in 24-hr time, rounded to the nearest hour*)	Closed All Day?	Open 24 hours?	Partial Op %	Average # of Occupants?
Weekdays	From _______ to _______	❑	❑		
Non-weekdays	From _______ to _______	❑	❑		
	From _______ to _______	❑	❑		
	From _______ to _______	❑	❑		

Describe any seasonal variations in the level of occupancy at this facility.

D. Demand Response Plans

Interview DR Contact. Ask about overall strategy to achieve Demand Response Reductions. What systems will be affected, what are the kW reduction goals? Review/confirm/expand results from telephone screening interview.

____

____

____

____

E. Demand Response Issues, Concerns, Monitoring Interests

Interview DR Contact. Ask about any issues or concerns they may have about the DR actions they are planning or DR actions they are considering but uncertain about. [Do not try to discuss issues related to program rules, payment, etc.] Probe on how these issues might affect the monitoring plan, e.g., locations for measuring light levels or temperatures, verifying savings from a particular control strategy or piece of equipment, etc. Ask participant for any suggestions or preferences they may have for monitoring while ensuring they understand this is a research project and you cannot promise them specifics at this stage.

____

____

____

F. Demand Response End Uses

Identify the end uses for which the customer plans to implement load reductions in response to the CPP or DBP events. Provide very approximate estimates of associated loads and load reductions for this site. This is general information – specific information is requested later in this form.

Facility/Site______________________ Utility Accounts_________________________

Number of Bldgs.________________ Utility Meter #___________________________

End Use	*Approx. kW*	*DR Plans (Y/N)*	*~% of Load Affected by DR*	*~Planned Load Reduction (kW)*
Lighting				
HVAC / Refrigeration				
Process loads				
Other				
Total				

Are detailed site plans/blueprints available? ______________

G. Controls Systems Summary

What types of energy management systems (EMS), energy information systems (EIS) and related controls systems are used for this site?

1.
___Make:________________________Model:_____________________Versions:_____________

___Software:______________________Communcation Protocols:________________________

2.
___Make:________________________Model:_____________________Versions:_____________

___Software:______________________Communcation Protocols:________________________

3.
___Make:________________________Model:_____________________Versions:_____________

___Software:______________________Communcation Protocols:________________________

4.
___Make:________________________Model:_____________________Versions:_____________

___Software:______________________ Communication Protocols:________________________

What systems are controlled?

____

____

____

What types of points?

____

____

Is the data trended and stored and, if so, for how long?

____

____

Is the system accessible remotely and, if so, how?

____

____

How might the data from these existing systems be used or augmented to meet the monitoring needs for this site?

____

____

____

____

H. SITE DIAGRAM

Provide a high-level, simple sketch of the facility focusing on the location of major functions and loads, e.g., office functions, industrial processes, HVAC equipment, and refrigeration equipment. Include multiple locations or floors as appropriate. Include multiple sheets if necessary.

ASK FOR FIRE EVACUATION PLANS – THESE ARE USUSALLY READILY AVAILABLE AND WILL SAVE YOU TIME

HVAC OPERATION

Does this facility expect to make changes to the operation of its space cooling equipment in order to respond to requests to drop load?

❑ No. *Go to Lighting Section.*

❑ Yes. *Collect following data.*

Identify the characteristics of the space cooling equipment (air conditioner / chiller) in this facility. Estimate affected portion affected by the Demand Response actions planned and list DR strategies.

	System 1	***System 2***	***System 3***	***System 4***
Primary/Secondary				
Fuel Type				
Equipment Type *(See List)*				
Quantity				
Total Capacity (tons)				
No. of Floors				
Total Floorspace cooled (sq. ft)				
Hours of use per day				
Temperature during:				
- Summer weekdays				
- Other periods				
Starting hour for daytime setpoint				
Ending hour for daytime setpoint				
Affected by DR Action Plan?				
% of Load Affected				
DR strategies *(see codes below)*				
Raised set-point target *(if applicable)*				

Equipment Types: 1 = Package 2 = Centrifugal 3 = Reciprocating 4 = Screw 5 = Scroll

List of DR Strategies

1 Raise temperature
2 Duty cycle fans and pumps
3 Turn off A/C units
4 Reset chilled water temp for chillers
5 Unload chillers

6	Pre-cool space
7	Other:____

Additional Detail on HVAC DR strategies, if needed:

____

____

____

____

____

If the temperature were increased in response to the DR, what would be the upper limit for the setpoint? ______________ ºF

Characterize the specific equipment components that will be affected by the DR actions?

Load	Qty	Total Ton or Hp (show units)	Number of Panels	Number of Circuits	Amps	Location		
						A	B	C
Chillers								
Pumps								
Fans								
Air Handlers								
Cooling Towers								
Packaged Units								

[As appropriate] Tie location of affected loads back to overall facility diagram or provide a new sketch of floor plan focusing on the location of affected HVAC loads.

Describe one or more preliminary approaches to monitoring the affected HVAC loads and, if appropriate, associated energy services (e.g., temperature, air movement, etc.):

____

____

____

____

____

____

____

How many temperature points need to be monitored to represent most areas affected by DR temperature resets? ____

IF there is an existing EMS or DDC systems, does it provide temperature data and how often (e.g., 5 minute intervals)?

- ❑ Yes _________ minute intervals
- ❑ No

If data collection strategy to be used involves recorders / loggers, and if temperature data are not available in 5 to 15 minute intervals -- What is the distance in feet between the logger and where temperature sensors can be placed in zones, and the estimated time to run the needed wiring?

1. __________ feet _________hours
2. __________ feet _________hours
3. __________ feet _________hours
4. __________ feet _________hours

If packaged units supply the cooling load, can a sample of them be monitored to represent the total?

___Yes, How many?_______

___No

Are Outdoor air temperature sensors recommended ? ____Yes _____No

Other HVAC Notes

____

____

____

____

____

____

____

____

____

____

LIGHTING SYSTEM OPERATION

Does this facility expect to make changes to the operation of its lighting equipment in order to respond to requests to drop load?

❑ No. *Go to Refrigeration Section.*

❑ Yes. *Collect following data.*

Table L1 - Baseline Lighting for and general extent affected by Demand Reduction:

General Location Code	*Location Description*	*Starting Hour*	*Ending Hour*	*Total Lighting kW*	*% of kW Affected by DR*
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Table L2 - Lighting systems details for systems affected by Demand Reduction (use multiple sheets if necessary):

Lighting Sub-Location Code (1)	***Sub-Location Description***	***Base Connected KW***	***No. of Fixtures***	***Fixture Type** (2) (one per row)*	***Normal Control Methods (3)***	***% Reduction in kW Due to DR Action***	***# of Fixtures Affected by DR***	***DR Control Strategies (3),(4)***

(1) lighting locations: To increase specificity, add decimal to in Table L1, e.g., 1.1 to 1.X, 2.1 to 2.X, etc.

(2) Fixture Type Codes: 1 -Linear Fluorescent 2- Incandescent 3- CFL 4 -HID 5 Other – Specify:____________

(3) Normal Lighting Control Method Codes: 1 Manual 2 DDC 3 Time Clock 4 Photocell 5 Other – Specify

(4) Lighting DR Control Strategy Codes – Combine with (3) Lighting Control Method Codes. (Example: Manual bi-level control of some fixtures = 1.4)			
1 - Turn off all	3 -Bi-level reduction / all	5 -Dim all	7- Other - Specify
2 -Turn off of some	4- Bi-level reduction in some	6 - Dim some	

How many circuit panels will be affected by the load reduction actions? _______________

How many lighting circuits will be affected by the load reduction actions? _____________

Additional Detail on Lighting DR strategies:

____

____

____

Table L3 – Location of lighting circuits/panels affected by DR lighting actions that are good candidates for sub-metering (this may be a sample of the population of affected circuits):

Panel Location	Entire Panels	Partial Panels	Associated Lighting Sub-Locations (From Table L2)	# of Circuits	Amp Rating
EXAMPLE: East Electric Rm.	Panel A		1.1, 1.2		100
EXAMPLE: North Electric Room		Panels B&C	1.3,2.1,2.2	20	15

[As appropriate] Tie location of affected loads back to overall facility diagram or provide a new sketch of floor plan focusing on the location of affected lighting loads.

Describe one or more preliminary approaches to monitoring the affected LIGHTING loads and, if appropriate, associated energy services (e.g., light levels):

____

____

____

____

____

____

____

____

Other Lighting Notes

____

____

____

____

____

____

____

REFRIGERATION OPERATION

Does this facility expect to make changes to the operation of its refrigeration equipment in order to respond to requests to drop load?

- ❑ No. *Go to Process Section.*
- ❑ Yes. *Collect following data.*

Identify the characteristics of the refrigeration equipment in this facility. Estimate portion affected by the Demand Response actions planned and list DR strategies.

	System 1	***System 2***	***System 3***	***System 4***
Primary/Secondary				
Equipment Type *(See List)*				
Quantity				
Total Capacity (tons)				
Floorspace cooled (sq. ft)				
Temperature setpoint				
24-Hours per day (Y/N)				
Heat Exchanger? (Y/N)				
Secondary loop (glycol, etc.)				
Affected by DR Action Plan?				
% of Load Affected				
DR strategies *(see codes below)*				
Raised set-point target *(if applicable)*				

List of Equipment Types: 1 = Centrifugal 2 = Reciprocating 3 = Screw 4 = Scroll

List of DR Strategies

1 Raise temperature
2 Turn off Refrigeration system
3 Unload compressors
4 Pre-cool product / warehouse/ walk-in
5 Use product storage to carry through the DR period
6 Other:____

If the temperature were increased in response to the DR, what would be the upper limit for the setpoint? ____________________ ºF

Characterize the specific equipment components that will be affected by the DR actions?

Load	Qty	Ton or Hp	Number of Panels	Number of Circuits	Amps	Location		
						A	B	C
Compresssors								
condensors								
Evaporator Fans								
Other Specify:__________								

[As appropriate] Tie location of affected loads back to overall facility diagram or provide a new sketch of floor plan focusing on the location of affected Refrigeration loads.

Describe one or more preliminary approaches to monitoring the affected Refrigeration loads and, if appropriate, associated energy services (e.g., temperature, air movement, etc.):

____

____

____

____

____

____

____

____

How many temperature points need to be monitored to represent most areas affected by DR temperature resets? ____

IF there is an existing EMS or DDC systems, does it provide temperature data and how often (e.g., 5 minute intervals)?

❑ Yes _________ minute intervals
❑ No

If data collection strategy to be used involves recorders / loggers, and if temperature data are not available in 5 to 15 minute intervals -- What is the distance in feet between the logger and where temperature sensors can be placed in zones, and the estimated time to run the needed wiring?

1. __________ feet _________hours
2. __________ feet _________hours
3. __________ feet _________hours
4. __________ feet _________hours

Any thermal loads need to be monitored? ____

Other Refrigeration Notes

____

____

____

____

____

____

PROCESS EQUIPMENT OPERATION

Does this facility expect to make changes to the operation of its process equipment in order to respond to requests to drop load?

❑ No. *Go to next section.*

❑ Yes. *Collect following data.*

Identify the process end uses and associated information for which Demand Response will implement load reductions and the estimated kW load reduction.

End-Use	***Total Load (kW)***	***% of Load Affected***
Pumps		
Fans		
Other Fans or Blowers		
Material Transporters		
Machine Tools		
Crushers / Grinders		
Stamping Machines		
Rolling or Pressing Machines		
Ovens / Dryers		
Kilns		
Heat Treating		
Arc Furnaces		
Injection Molding		
Air Compressors		
Battery Chargers		
Other		
Other		
Other		
Other		

How is process controlled now: ❑ Manual ❑ DDC ❑ Time Clock
❑ Feedback sensors

What type of action do you intend to take to change operation of process equipment in response to DR?

❑ Turn off loads ____Entire DR period ____Part of DR period

❑ Reduce motor speed

❑ Reduce output capacity – turning off equipment

❑ Duty Cycle equipment

❑ Change Temperature Settings

❑ Other

Additional description: ____

Will production or quality of product be effected by DR? _________, How _______________

____

List all equipment that will be affected by DR.

Equipment Type	*Number*	*Total kW*	*Voltage*	*Max # of hours Load Stays Off*	*# of Panels*	*# of Circuits*	*Location*		
							A	*B*	*C*

Are any of the equipment affected by the DR constant load?

❑ No
❑ Yes (list of loads) ______________________________________

____

Other Process Notes

[As appropriate] Tie location of affected loads back to overall facility diagram or provide a new sketch of floor plan focusing on the location of affected process loads.

GENERAL MONITORING ISSUES

Summary of monitoring type recommended for the Demand Response effected systems:

Load Type

___________ Continuous measurement of kWh for all effected loads

___________ Continuous measurement of kWh for a sample of the effected loads

___________ Continuous monitoring of event indicators (on or off) for all HVAC system components with one-time kW measurements

___________ Continuous monitoring of event indicators (on or off) for a sample of HVAC system components with one-time kW measurements

___________ Continuous monitoring of indoor air temperatures or setpoints through existing controls system

___________ Continuous monitoring of a sample of indoor air temperatures through installation of new sensors

Is this site appropriate for a parallel N Box to obtain data from the existing EMS and/or collect data from new monitoring points:

❑ Yes List Load Types: ___________________________

❑ No ___________________________

____

Can any of the controlled loads be monitored by the status of the control points and of a set of one-time measurements of kW of the load?

❑ No (If No, skip to A.)

❑ Yes (list of loads) ___________________________

____

____

If yes, what type of signal can be used to monitor for on & off time periods?

___ Circuit breaker

___ Output from DDC

___ Lighting level sensors

___ Time clock

___ Output from DDC

___ Feedback Sensors

Number of relay switches needed by voltages?

___277V ___120V ___24V ___5Vdc ___Other______

Number of digital status channels needed?________________________________

A. What is the total number of circuits feeding the loads for:

HVAC ____

Lighting ____

Refrigeration ____

Process ____

What is the number of circuits needed to be monitored? ___________________________

What is the operating voltage? ____ 120/208 Vac ____ 277/480 Vac More______

What is relative distance between electrical panels that may need to be monitored?

____In the same room or area

____In the same vicinity with possibility of running low voltage wiring between them

____Distributed in different parts of the building

Show location of the panel(s) on sketch of floor plan.

How much time will be needed for wiring between sensors/CTs and logger?

___ Under 2 hours

___ Under 4 hours

___ Over 4 hours

Do any of the wires need to be in conduit? If yes, how much conduit work needed?

____feet

____hours required

Number of electric load channels needed ___________________

Number of current transformers (CTs) needed & ratings ___________________

Number & type of loggers needed?

___ Synergistic C-___

___ DataTrap

___ Highland K-20

___ Apptech

___ Elite Pro

___Other

Indicate the location to mount the logger(s) on the floor plan sketch.

Type of telecommunication recommended for the loggers

___ Dedicated line available from business

___ Share line with business, use only during off hours

___ Share line with business using plug-in phone line director

___ New line to be installed

___ Cell phone connection is only feasible approach and cell phone can be placed where it will receive signal.

___ Tie in to existing EMS

___ Tie into Parallel N Box

Can the phone wire be run to the loggers with?

___ Easy access

___ Under 2 hrs

___ Extensive effort

Any time restriction for installation of the monitoring equipment?

___ Day of week_____________________________________

___ Working hours___________________________________

Would the installation require any power interruption to the business?

___ No

___ Yes, Explain____

Is the engineering or maintenance department agreeable to the monitoring approach?

❑ Yes

❑ No

Provide an estimate of installation time: # of hours ___________________

Is any special equipment needed for installation, such as a tall ladder?

❑ Yes ____

❑ No

Are there any other restrictions or protocols required by the site to be followed for monitoring equipment installation? Please explain: ____

____

____

[As appropriate] Tie location of affected loads back to overall facility diagram or provide a new sketch of floor plan focusing on the location of affected loads.

Other Information or Notes

APPENDIX K.5
DATA POINT SUMMARY FORM

Attached on the following pages is the Data Point Summary Form.

DATA POINT SUMMARY

Site ID#: __________________ (use account number or other unique identifier)

Recorder Type____________ Recorder ID:________ Recorder S/N:___________

Recorder Phone: ____________ Installer Name: _____________ Date: _________

Site Name:____________________________________

Site Contact Name:______________________________

Site Contact Phone 1:____________________________

Site Contact Phone 2:____________________________

Recorder/ Logger No.	Chan. No.	Channel Description	Chan. Type (kW, analog or digital)	Unit of Measure (UOM) *	End-Use Category (EUC)	Multiplier	Offset	CT ratio	Spot KW Measurement	Comment (see below)	
1	1	Chilled Water Pump	CT/kW	O2	HVAC	1	0	600: .333	5.3 kW	A	EXAMPLE
1	2	Outside Air Temp	Analog	O5	n/a	1	0	n/a	n/a	B	EXAMPLE
										C	
										D	
										E	
										F	
										G	
										H	
										I	
										L	
										L	
										M	
										N	
										O	
										P	
										Q	
										R	
										S	
										T	
										U	

** UOM Codes: 01=kWh; 02=kW; Temp=05; Volts=11; Amps=12 RelHum=18; GPM=19; CFM=20; Percent=21; KBTU=22; MBTU=23; in WC=24; Min/Interval=29*

RELEVENT DR RELATED COMMENTS:

A) *Example:* channel 1 captures 1 of 3 Chilled water pumps used in curtailments (covers 33% of curtailed pump loads)

B) *Example:* Air Temp Sensor placed on N. side of building near O/D air intake. Expected temp. range 55-105 degree F