Results from a Real-Time, Statewide Evaluation of Large C&I Demand Response Programs in California

Evaluation of California IOU's 2004 Critical Peak Pricing & Demand Bidding Programs

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ABSTRACT

This paper presents a summary of results from a comprehensive evaluation of the 2004 Critical Peak Pricing (CPP) tariff and Demand Bidding Program (DBP) implemented by California's investor-owned utilities (IOUs). The evaluation included process evaluation, a market assessment, a load baseline analysis, and an impact evaluation. The paper outlines the evaluation activities and summarizes key findings. In the summer of 2004, few critical peak events were called and most of the DBP events were test events. Participation levels for the CPP were very low despite the fact that the tariff was revenue neutral (that is, half of eligible customers could reduce their bills on the CPP without making any reductions in their peak demand). DBP participation levels were higher, in terms of accounts and load signed up, however, the vast majority of signups did not place bids or otherwise take demand response actions during the events called in 2004. Project-related market research revealed significant technical potential for demand response. In contrast, estimated market potential, at incentive levels similar to those provided by the 2004 CPP and DBP, was found to be much more limited.

Based on results of this evaluation, the market needs stronger motivation, knowledge, and capability in order for these programs to make large contributions to the state's price-responsive DR goals. Recommendations are provided for how to increase program participation and impact levels, including increasing the financial benefits of participation, helping customers to prepare and implement DR strategies, increasing the amount of time for bids to be placed, and increasing the number of events called. In addition, it is recommended that a formal analysis of DR costs and benefits be conducted to better inform policy decisions regarding current and future program features.

INTRODUCTION

In 2002, the California Public Utilities Commission (CPUC) adopted an Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing." Following this ruling, the CPUC authorized Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) to implement a voluntary Critical Peak Pricing (CPP) tariff and Demand Bidding Program (DBP) for large (over 200 kW) customers. The goal underlying these DR programs was to provide California with greater flexibility in responding to periods of high peak electricity demand. This paper presents a summary of results from an evaluation of the 2004 CPP and DBP programs. The evaluation was performed under the guidance of an advisory committee consisting of representatives from the IOUs, the Energy Commission (CEC), and the CPUC.

As part of its proceeding on demand response, the CPUC put forth a progressive set of load reduction goals for the California investor owned utilities (IOUs). Table 1 presents the specific goals for the California IOUs' price-responsive DR programs. Note that these goals were for all DR programs, that is, those affecting all customers, not just the large customer group that is the focus of this paper.

Table 1. Overall CPUC Price-Responsive Demand Reduction Goals (2003/2004 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

OVERVIEW OF PROGRAMS

The following 2004 DR programs were designed to contribute to the peak savings goals above were thus were included in the evaluation:

- The Critical Peak Pricing (CPP) tariff
- The Demand Bidding Program (DBP)
- The California Power Authority Demand Reserves Program (CPA-DRP)
- The Hourly Pricing Option (HPO) tariff (for customers in San Diego Gas & Electric's territory)
- Transitional DR Incentives

Midway through the evaluation the scope was expanded to include a comparative description of the California IOUs' interruptible programs. In addition, the HPO program was dropped from the scope due to the absence of any program participation. The paper focuses solely on the evaluation for the CPP and DBP programs (including the associated transitional incentives). Readers should refer to the full evaluation report for additional details and results for the DRP and interruptible programs (Quantum, 2004c). A summary of the CPP and DBP program designs, along with a brief description of the transitional incentives designed to encourage early customer participation follows.

Critical Peak Pricing Tariff

The 2004 Critical Peak Pricing (CPP) tariff was a voluntary summer season program designed to encourage customers, who are greater than 200 kilowatts (kW), to shift some of their summertime power usage to the mid- and off-peak time periods during critical peak times. The rate included increased prices during 6 or 7 hours (Noon to 6pm for PG&E and SCE, 11am to 6pm for SDG&E) for up to 12 "Critical Peak Pricing" days and reduced prices during non-critical-peak periods. Specific prices in the tariff were applied based on participating customers "Otherwise Applicable Tariff" (OAT). Peak prices varied from 5 to 10 times OAT depending on the utility.

Demand Bidding Program

The 2004 Demand Bidding Program (DBP) was a voluntary demand bidding program that offered incentives to customers for reducing energy consumption and demand during specific DBP event periods. The program was available year round to bundled service customers with demands greater than 200 kW and who could commit to reduce a minimum of at least 100 kW per hour (later reduced to 50kW) during a DBP event period. Bidding was an offer to curtail usage by 100 kW or more for two or more hours during program "events" and receive payment equal to the amount of the estimated reduction times the predetermined DBP price incentive. DBP price incentives ranged from $0.15 to $0.50 per kWh reduced depending on market prices and whether the event was a day-of or day-ahead event.

Transitional Incentives

The following two incentives were offered in 2004 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 new 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' requests to the CPUC to modify the incentive, the 3 percent requirement was eliminated.
- The Technical Assistance incentive offered CPP or DBP participants a cash incentive of up to $50 per kW of estimated 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; to receive the other half, customers had to provide actual load reductions averaging at least 50 percent of the certified amount during CPP or DBP peak events. No customers ultimately went through the process of obtaining these incentives.

EVALUATION OBJECTIVES AND APPROACHES

The evaluation design was developed to achieve both process and outcome objectives. The immediate focus needed to be on observing the first steps of program rollout 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 was comprised of a number of sub-studies, phases, and deliverables. The core sub-studies included a process evaluation, a market assessment, a load baseline analysis, and an impact evaluation. The basic evaluation objectives were developed by Working Group 2 participants and published in the Second Working Group 2 report (WG2 2002). The evaluation scope of work was further developed by the Working Group 2 Measurement and Evaluation Subcommittee (M&E Committee) and Quantum Consulting developed the final Research Plan in cooperation with the M&E Committee. The process evaluation focused 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 assessed the performance of different representative-day methods of estimating peak savings as a function of selecting different baseline or representative days. The impact evaluation estimated peak load impacts for the 2004 events and compared results across baseline load estimation methods. (Results of the baseline load estimation analysis are presented in Buege, et al., 2005.)

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, 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 Table 2. As shown in the table, three reports were provided during this study, along with several presentations, each of which were timed to coincide with key regulatory deadlines and activities throughout 2004. Table 3 summarizes the key data collection activities included in the evaluation.

Table 2. California Large C/I DR Evaluation 2004 Products and Activities

CA C/I DR Evaluation Product	Evaluation Activities
Summary of Phase 1 Research Report *(April 2004)*	• Summarize and assess DR marketing efforts • Preliminary assessment of awareness, participation, decision making, obstacles • Findings and recommendations to support utilities' spring '04 DR filings • Identify key issues and questions for next phase of research
Non-participant Market Survey Report *(August 2004)*	• Survey of non-participant commercial and industrial customers • Baseline information on DR awareness, familiarity, participation likelihood, load reduction potential, decision-making processes, etc. • Recommendations for increasing program participation levels
Final Report *(December 2004)*	• 2004 participation analysis • Post-event and end-of-summer customer survey • Analysis of baseline load estimation methods and assessment of program impacts • Process evaluation findings • Interruptible program evaluation and CPA-DRP evaluation • Recommendations for increasing Large C/I DR load impacts

Table 3. Summary of 2004 CPP-DBP Evaluation Data Collection Activities

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
Analysis of Participant Interval Data	772
Analysis of 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

Table 4. 2004 CPP and DBP Program Signups Across All Utilities

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

2004 Program Events

Although the evaluation was designed to estimate peak load impacts across the full range of potential program events, as it turned out, only a limited number of events were called for those programs with the largest numbers of participants.

DBP Events. 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.

CPP Events. 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 average daily temperatures significantly decreased. Although the SCE program was called 12 times, there were only eight SCE participants.

KEY FINDINGS

This section presents a summary of key findings from the 2004 CPP and DBP Evaluation. Findings related to the analysis of baseline load estimation methods are provided in a companion paper

(Buege, et al., 2005). Detailed findings from the baseline market survey are available in Quantum, 2004b.

Significant Levels of Program Awareness and Familiarity

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 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 account representatives.

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

As presented above, only 1 percent of eligible accounts participated in CPP for summer 2004. The CPP was designed to be revenue neutral to the utilities and so, 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, 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 rate itself as well as future changes in their load shapes due to weather or other factors appears to have limited participation significantly in 2004.

For DBP, only 43 of 607 SCE DBP participants bid load for at least one of SCE's two DBP test events. This represented only 7 percent of those signed up for the program. Even though these were only test events, this was a very small fraction of signups and was 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 because 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 system critical peak events, particularly if customers believe system reliability is at risk. Program managers and a portion of interviewed customers indicated 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. Results from evaluation interviews with participants indicated 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.[1]

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

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

amount they were required to specify when they signed up for the program).[2] In any case, analysis of the PG&E Day-Of DBP event indicates that only a third of participants reduced load by 100 kW or more.

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. 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. In general, low levels of bidding in 2004 appear to reflect lack of experience, knowledge, and capability for some customers.

Load Reduction Impacts: Wide Range in Peak Load Reductions and Participant Activity

The impact estimates for the 2004 CPP and DBP programs were developed through application of baseline load estimation methods described in a companion paper Buege, et al., 2005. As noted in the companion paper, the results were very sensitive to the effect of a small number of large customer participants for whom baseline usage estimates were very uncertain.

CPP 2004 Impacts. The overall estimated load reduction was roughly 8 MW for the 2004 CPP across utilities. PG&E accounted for 60 percent of the estimated impact, SDG&E 30 percent, and SCE 10 percent. On a percentage basis, the average impacts ranged 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.

The mean impact estimated for PG&E was 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 (i.e., including impact estimates for the last two events, which are believed to be biased upward), the mean impact was 9 percent. For SDG&E, the average impact across its six CPP events was 15 percent. For SCE, which only had eight participants, the estimated impact was 55 percent of load; however, this value was driven primarily by a single customer. (For SCE, the median impact was 9 percent.)

DBP 2004 Impacts. As with the CPP impacts, it was difficult to identify a reliable DBP impact estimate that could be used prospectively to forecast expected savings given the limitations associated with the 2004 results. This was primarily because, as discussed previously, there were very few DBP events, most of these were test events, and very few of the customers signed up for the program placed bids for these events. Within the constraints of these caveats, we estimated the overall load reduction associated with these primarily test events as roughly 27 MW for the 2004 DBP across utilities. PG&E accounted 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). The estimated impact across all SCE and SDG&E DBP signups was 2 percent and 4 percent, respectively. However, for SCE and SDG&E, impacts *across only those who placed DBP bids* ranged from 12 to 50 percent for SCE, and 19 to 28 percent for SDG&E. As discussed previously, because there were so few bidders for the SCE and SDG&E events (less than 5 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.

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

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

There is evidence that the 2004 levels and form of compensation did not motivate 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 value of 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.). 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).

Many Customers Perceive High Barriers to Demand Response

Based on the results of the non-participant DR baseline survey conducted as part of this evaluation (see Quantum, 2004b for full survey results), customers indicated that there were numerous barriers that limited 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 "Insufficient Amount of Potential Bill Savings", "High Levels 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 "Insufficient Amount of Potential Bill Savings", "Complexity of Program Rules", "Uncertainty over Future Program Changes", and "High Levels of On-Peak Prices or Non-Performance Penalties".

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 were not 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.[3] Based on rough initial estimates of the range

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[3] 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.

of coincident peak demand for this population, the total technical MW reduction potential is likely in the range of 1,600 MW. Note, however, that technical potential assumes the customer received sufficient financial motivation, 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.[4] The magnitude of DR potential drops when customers are asked to report how much they would require in bill savings to deliver DR load reductions.[5] 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. 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.

Adequacy of Notification and DBP Bidding Timing

The California IOUs 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.

Even so, 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 appeared to need less time to actually curtail usage than 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 requires 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 in 2004 may be explained in part by survey responses about the amount of time required both to submit bids and curtail load. In explaining why the one-hour time 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).

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[4] 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.

[5] 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.

Conflicting Information on Customer Need for Additional Technical Assistance

The extent of customer need for DR technical assistance was unclear based on the empirical and anecdotal findings from the evaluation. In close-ended surveys, customers tended to indicate that they were knowledgeable about their DR options and did not volunteer requests for technical assistance when asked what more could be done to encourage their participation. In addition, no customers went through the entire process of receiving the Technical Assistance incentives designed for CPP and DBP participants. Nonetheless, in-depth interviews with customers and site visits associated with the sub-metering portion of this evaluation found numerous cases where customers either asked for support or were clearly in need of technical support to develop a DR implementation plan. The Technical Assistance Incentives as originally designed clearly placed risk onto customers and did not work. General DR assistance is also available to customers through the CEC's Enhanced Automation project (CEC, 2003), 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.

CONCLUSIONS

The DBP and CPP program results for 2004 can be assessed differently depending on the contextual lens through which they are viewed. The findings and recommendations were developed within a context of urgency with respect to the CPUC's desire for the utilities to meet its aggressive DR goals. In an environment that lacked the urgency associated with meeting these aggressive goals, the tone of findings and recommendations presented 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, it could be concluded 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, the charge of the 2004 evaluation was to assess the 2004 program experience from the perspective of how likely customers 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 were only actively marketed since late 2003, the results of this research provided fairly strong evidence that the 2004 CPP and DBP programs would 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 programs to make large contributions to the state's price-responsive DR goals if participation in demand response programs and/or tariffs is to remain voluntary. Readers should note, 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 and program impacts can be projected for 2005 and beyond.

RECOMMENDATIONS

This section presents a summary of selected recommendations that resulted from the evaluation of the CPP and DBP programs.

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. As discussed above, 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 preferable to have a guaranteed minimum number of program events. There are also program benefits to ensuring a minimum number of actual program events, in particular, to increase the certainty of the estimated DR resource availability and to maintain customer focus. 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.

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 and bill savings potential for participants in both the CPP and DBP programs appear insufficient to motivate significant portions of the market to seriously consider participating. 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 customers, however, the level of benefit is very small, on the order of 1 percent of their annual bill. This is the result of a design that attempted to minimize the bill impacts on those customers whose bills would rise if they did not respond and at the same time collect the same amount of revenue from this customer class. According to the utilities' rate analyses, even with peak load reductions of 20 percent during CPP events, PG&E and SCE customers that benefit on CPP 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. Of course, increasing customer benefits from the CPP tariff may not be easy given the constraint of revenue neutrality, nor may all stakeholders agree that this is justifiable given current market prices.

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 fixed costs necessary for successful participation. In addition, customers may sign up for the program but not be engaged in active participation. For these reasons, several programs around the country 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. Customers' desire simpler, more unified programs that include some element of a capacity payment.

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. The IOUs should help and encourage participants 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.[6]

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, 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 tier based on how quickly the bid is received.

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. There are many cases in which customers are unsure of the kinds of DR actions they could implement, how they can 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 this so that fixed 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.

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

It is imperative that a DR valuation framework is agreed upon and that a cost-effective analysis is completed to better inform policy making regarding these programs. A threshold concern about the CPP and DBP programs is whether these voluntary programs, with the current levels of customer

[6] However, 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.

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 quantification of the value of reducing peak load now and in the future for targeted time periods in the summer.

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