Decision 06-11-049 November 30, 2006

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), for Approval of 2006–2008 Demand Response Programs and Budgets.	Application 05-06-006 (Filed June 1, 2005)
Southern California Edison Company's (U 338-E) Application for Approval of Demand Response Programs for 2006-2008 and Cost Recovery Mechanism.	Application 05-06-008 (Filed June 1, 2005)
Application of San Diego Gas & Electric Company (U 902-E) for Approval of Demand Response Programs and Budgets for Years 2006 through 2008.	Application 05-06-017 (Filed June 2, 2005)

ORDER ADOPTING CHANGES TO 2007 UTILITY DEMAND RESPONSE PROGRAMS

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ORDER ADOPTING CHANGES TO 2007 UTILITY DEMAND RESPONSE PROGRAMS

I. Summary

This order adopts a number of augmentations and improvements to existing utility demand response programs and budgets originally adopted in Decision (D.) 06-03-024.[1] The Commission adopts these changes in order to promote system reliability during the summer peak demand periods of 2007 and 2008. To this end, we adopt the following modifications to the demand response programs of Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE):

A. Programs Common to Multiple Utilities

1. Base Interruptible Program (BIP)

- PG&E**:** Adopts increased incentives for Option A. Authorizes a new option that offers incentive payments of $0.60/kWh for participation, no capacity payment, no penalty for non-participation, 4 hours notice, and called only when deemed prudent by PG&E. Allows aggregators to participate.

- SDG&E**:** Adopts penalty reduction of 25%, adds additional triggers, adopts changes to Rule 29, and directs SDG&E to permit aggregators to sign up customers with less than 100 kW loads as long as the aggregated load exceeds 100 kW.

[1] "Demand response gives an individual electric customer the ability to reduce or adjust their electricity usage in a given time period, or shift that usage to another time period, in response to a price signal, a financial incentive, or an emergency signal." (D.03-06-032, Attachment A, "California Demand Response: A Vision for the Future (2002-2007)").

- SCE: Directs SCE to permit third-party aggregator participation.

2. Demand Bidding Program (DBP)

- All IOUs: Adopts a flat rate incentive of $0.50 for day-ahead calls and $0.60 for day-of calls, adopts "soft" triggers, enlarges the bidding windows, and approves enrollment simplifications.

3. Air Conditioning Cycling Programs

- PG&E: Approves in concept a 2007 AC cycling program that would install 5,000 switches using the existing demand response budget and subject to advice letter review of the detailed budget.

- SDG&E: Adopts new options: 100% cycling for residential and 30% cycling for commercial, adopts weekend events, and directs SDG&E to improve its website.

4. Demand Response Request for Proposal (RFP)

- PG&E and SCE: Directs utility to move forward with their proposals to run an RFP or seek bilateral contracts for new demand response programs, and requires the utilities to file applications for Commission approval of specific contracts.

5. Technical Assistance/Technical Incentives (TA/TI)

- All IOUs: Increases per kilowatt TA/TI incentives to encourage customer adoption of demand response enabling technologies.

6. Auto DR

- All IOUs: Authorizes use of existing TA/TI funds and directs the utilities to work with the Demand Response Research Center to develop detailed proposals.

7. Permanent Load Shifting

- All IOUs: Directs each utility to pursue RFPs and bilateral arrangements for permanent load shifting to be implemented by summer 2007, and to file an advice letter with its proposal by February 28, 2007.

8. Critical Peak Pricing:

- PG&E: Eliminates geographic zones, and earlier customer notification.

- SDG&E: Adopts soft triggers and increases event maximum to 15.

B. PG&E Programs

1. Small Customer Aggregation Pilot Program:

- Allows SF Power until June 1, 2007 to reach its 2006 goal of signing up 1 MW, authorizes additional funding when performance goals are met, permits expansion to two additional counties, and authorizes development of a permanent load shifting program.

2. Business Energy Coalition:

- Authorizes PG&E to expand the program to 50 MW in 2007 using the existing demand response budget, and directs PG&E to propose extending the program beyond 2008 in an application.

C. SDG&E Programs

1. Commercial and Industrial Peak Generation Program:

- Restructures the incentive payment format by providing payment for reductions between 10% and 20%, and softening the triggers. For 2007 and 2008.

2. Residential Smart Thermostat Program:

- Extends the program through 2007.

3. In-Home Display Program:

- Implements a new program that will offer residential customers an in-home display device that will provide information to customers on their energy usage and potential cost by the hour, month and month-to-date.

II. Background

On March 15, 2006, the Commission issued D.06-03-024, which adopted 2006-2008 budgets for the demand response programs of SCE, PG&E, and SDG&E. These program budgets were proposed as part of a settlement filed by the active parties to the proceeding.

Since the issuance of D.06-03-024, the State of California experienced an unusually intense heat wave in July 2006, which at times strained the state's electrical system. In an effort to make the most of existing opportunities to protect the state's electrical system from compromises to its reliability, the Commission reopened this proceeding by ruling dated August 9, 2006 to augment utility demand response programs for 2007 and 2008. The ruling directed the three applicant utilities to propose program augmentations and improvements and also directed each utility to provide a preliminary assessment of the performance of each demand response program during the month of July 2006. This assessment would help the Commission improve demand response programs in the near term. On August 22, 2006, the Commission issued a second ruling in these consolidated proceedings directing the utilities to propose automatic demand response (Auto DR) programs, which envision the installation of control equipment that would affect load reductions. The utilities were also directed to identify ways to expand the role of demand aggregators, to encourage the deployment of Auto DR, increase program participation, and improve program performance.

The utilities filed proposals and program assessments on August 30, 2006. The Commission subsequently conducted a workshop on September 6, 2006, at which the utilities and other parties discussed program elements and potential improvements. On September 15, 2006, parties filed opening comments on the utilities' proposals and reply comments on September 22, 2006. Parties that filed opening comments are PG&E, SDG&E, SCE, Aglet Consumer Alliance (Aglet), Association of California Water Agencies (ACWA), California Large Energy Consumers Association and the California Manufacturers and Technology Association (CLECA/CMTA), Division of Ratepayer Advocates (DRA), EnergyConnect, Inc (ECI), EnerNOC, Inc. (EnerNOC), Energy Users Forum (EUF), Ice Energy Inc. (Ice Energy), San Francisco Community Power (SF Power), Silicon Valley Leadership Group (SVLG), and The Utility Reform Network (TURN). PG&E, SDG&E, SCE, Aglet, ACWA, the California Independent System Operator (CAISO), DRA, EnerNOC, and SVLG filed replied comments.

Some parties included in their filings assessments of advice letters the utilities filed in recent months seeking new or modified demand response programs, such as SCE's Advice Letter 2032-E, which proposes changes to its I-6 tariff and Base Interruptible Program (BIP) and SCE's Advice Letter 2034-E, seeking authority to expand its Air Conditioning (AC) Cycling program. Because the Commission did not grant the requests of some intervenors to merge those advice letters into these proceedings, we do not address the advice letter topics here.

III. Demand Response Program Performance in July 2006

A. PG&E

PG&E called on several demand response programs in July 2006, among them, the Business Energy Coalition (BEC), Demand Reserves Partnership (DRP), Critical Peak Pricing Program (CPP), Demand Bidding Program (DBP), BIP and the Non-Firm Program. The sum of the average load drops attributable to each of PG&E's programs was about 478 megawatts (MW) in July. The DRP and the Non-Firm program provided the largest share of energy reductions, with DRP providing 211 MW of load drop and the Non-Firm program providing about 197 MW of load drop.

B. SCE

SCE's demand response programs contributed to load reductions during the July heat wave. On July 24, 2006 after the CAISO called a Stage 2 Emergency, SCE called a total of eight demand response programs with an aggregate maximum load reduction of 809 MW. During July 2006, "day-of" programs contributed 755 MWs of load reduction and "day-ahead" programs contributed 54 MW. The vast majority of load reductions – more than 590 MW – are attributed to SCE's I-6 tariff.[2] On July 24, SCE experienced 97% compliance with the requirement for its 464 I-6 customers to drop load. SCE also reports that by the time SCE notified these customers to drop load, some had already voluntarily reduced demand by about 100 MW. SCE also reports that its BIP

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[2] I-6 is a rate discount program open to bundled and Direct Access Customers able to provide a minimum demand reduction of 500 kW with 30 minutes notice during an CAISO Stage 2 emergency or a localized system emergency.

customers reduced load on July 24 by as much as 75 MW during a 15-minute period. The BIP is very similar to the I-6 tariff except that it is offered to customers with demand of 200-499 MW. Not all BIP customers reduced demand in every time interval. On average, BIP customer demand exceeded available service by 13 MW.

C. SDG&E

SDG&E reports reasonably good participation by demand response customers during several July 2006 events. Demand response customers subscribing to day-ahead programs reduced load by an hourly average of 28 MW, with high levels of participation by CPP and DRP subscribers. Its day-of subscribers reduced load by an hourly average of 18 MW, most of which came from its AC Cycling program and smaller amounts from several other programs.

IV. Policy Issues and Standard of Review

As the events of July 2006 suggest, utility demand response programs are a key element of a broader and integrated approach to system management that engages customer's system demand during periods of critical need and potential system instability. Although there is much work to be done, the utilities and their customers continue to identify ways to improve existing demand response programs and propose innovative new ideas.

Our informal investigation of the July 2006 heat wave suggests utilities, energy providers and consumers alike contributed to the successful management of the state's energy system during that time. The need for the extraordinary efforts undertaken to prevent a system compromise during July, however, motivates us to pursue demand response programs that are more aggressive, more successful, and more inventive as part of a broader effort to assure system reliability and reasonably priced energy.

We anticipate the program modifications we adopt today will improve system reliability in 2007 and beyond. Some programs will be more successful than others. Most can be funded by redeploying previously authorized demand response money. We believe the costs associated with changes adopted here are in the public interest because we believe the cost of a vulnerable statewide electrical system would be unacceptably high to most of California's energy customers, particularly business customers. We take swift action in this proceeding because many of the program modifications the utilities propose will require significant advance marketing, and in some cases implementation, in order to have commitments of energy and capacity by summer 2007. Additionally, several relevant policy issues arose during this abbreviated proceeding and the parties articulated some broad areas of concern. Some of the program modifications we adopt today implicate Commission policy to some extent. However, we have declined making major policy determinations here. Instead, we intend to revisit these major policy issues in a forum in the near future that will permit more deliberation and the presentation of better information and analysis.

We commend the utilities and all of the participating parties to this proceeding for their expedited work on these demand response matters, and for the many insightful assessments they provided, as well as some innovative ideas.

The following discussion addresses a several policy issues that parties highlighted at the workshop and in comments.

A. Demand Response Program Goals

In 2003 a working group including CPUC and California Energy Commission (CEC) participants developed a vision for demand response: "All California electric consumers should have the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals, by not later than 2007." [3] The document also laid out objectives, goals, principles and a timeframe for achieving that vision. In D.03-06-032, the Commission endorsed several aspects of the vision statement, including a goal of achieving price-sensitive demand response capacity of 5% of annual system peak demand by July 1, 2007 and interim year MW targets for each of the IOUs. The adopted goals were specified to be above and beyond any "demand response achieved through the emergency programs…"[4]

In June 2004, the Administrative Law Judge issued a ruling recognizing that the 2004 targets for price responsive demand would not be met and modified those targets for that year only.[5] The Commission has not subsequently modified the original MW targets and goals. In January 2005, the Commission approved budgets for 2005 demand response programs and provided clarification on the issue of counting different types of demand response programs toward the goals.[6] In this decision, the Commission distinguished

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[3] The document "California Demand Response: A Vision for the Future (2002-2007)" is included in D.03-06-032 as Attachment A. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/26965.htm

[4] D.03-06-032 at 8.

[5] "Administrative Law Judge's Ruling Approving 2004 Schedule and plan for the Statewide Pricing Pilot and Establishing Process for Evaluation of Proposed 2005 Price Responsive Demand Programs", June 2, 2004. http://www.cpuc.ca.gov/word_pdf/RULINGS/37089.doc

[6] D.05-01-056.

between "price-responsive" and "reliability triggered" programs.[7] It clarified that only price-responsive programs would be counted toward the demand response goals. To provide clear guidance to the IOUs, we distinguished as "price-responsive" those programs designed to be triggered in anticipation of high peak demand on the next day ("day-ahead" programs). Programs in which events were triggered due to same-day reliability needs ("day-of" programs) were defined as "reliability" programs.[8]

In D.05-11-009, we identified a number of future activities related to demand response.[9] Among those activities were the need to develop appropriate measurement and evaluation (M&E) protocols and cost-effectiveness methodologies for demand response programs and tariffs. We directed agency staff to develop a set of draft M&E protocols and to hold a workshop with interested parties on development of cost-effectiveness tests. A workshop was held on March 21, 2006 and the draft Protocols were distributed to the service lists of R.02-06-001, A.05-06-006 et.al. and A.05-01-016 et.al. on April 3, 2006. Agency staff reported at the September 6, 2006 workshop in this proceeding that a proposed Order Instituting Rulemaking on demand response measurement and evaluation and cost-effectiveness was under development.

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[7] In "price-responsive" programs, customers choose how much load reduction they can provide based on either the electricity price or a per-kilowatt (kW) or Kilowatt-hour (kWh) load reduction incentive. In "reliability-triggered" programs, customers agree to reduce their load to some contractually-determined level in exchange for an incentive, often a commodity price discount. (D.05-01-056, p. 4.)

[8] D.05-01-056 at 7.

[9] "Decision Closing This Rulemaking and Identifying Future Issues Related to Demand Response, D.05-11-009, November 18, 2005.
http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/51376.htm

Our immediate need to augment demand response resources of both types should not be interpreted as abandoning the price-responsive goals. Had those goals been met, the reliability benefits provided by new price-responsive tariffs and programs would likely have made our recent orders directing the IOUs to procure new peaking generation, expand direct load control and otherwise augment demand response programs unnecessary. However, we acknowledge that a number of the mechanisms envisioned in the demand response vision statement—particularly development of transparent and robust day-ahead and real-time energy markets and the installation of advanced metering infrastructures for all customers—have not proceeded as quickly as we had anticipated. We have also learned a great deal from the various evaluation efforts that have accompanied demand response program implementation over the past four years, particularly concerning the measurement of demand response impacts and the difficulties of quantifying those impacts for settlement and resource adequacy purposes as well as for meeting the price-responsive goals.

The utilities raise a number of issues concerning the goals in their August 30, 2006 filings. A number of parties echo those concerns in their comments. These issues include the measurement and counting issues identified above, concerns about the "day-ahead" and "day-of" distinction, and the exclusion of reliability programs toward the goals. PG&E and SDG&E propose modifying the existing demand response goal to include reliability programs. SVLG and CLECA/CTMA agree, observing that demand response programs identified as "reliability" programs have been more successful than price responsive programs in terms of participation by and responsiveness of customers. DRA does not support counting reliability programs toward the utilities' price responsive goals, but could support a short-term change to the price responsive goals if the utilities petition the Commission to change the goals. DRA does, however, recommend that reliability programs should be the focus of this proceeding.[10] We acknowledged these concerns with the goals in D.06-03-024 and directed that they should be revised in another proceeding. At this time, we find no compelling reason to address these goals in this decision.

PG&E worries that it will be faulted for pursuing reliability programs rather than price-responsive programs.[11] The August 8, 2006 assigned Commissioner Ruling and the subsequent rulings addressing reliability needs for summer 2007 direct the IOUs to propose augmentations to their entire demand response portfolio, including both their price-responsive and reliability demand response tariffs and programs. This blending of the demand response categories reflects our heightened concerns for system reliability in summer 2007. The proposals include a broad portfolio of options, and, as with any other activity, we expect that the IOUs will pursue those options we approve with the same degree of effort whether or not they will be counted toward a goal. We dismiss the premise that the IOUs would fail to exercise diligence in pursuing all potential demand response resources. Agency staff have previously been directed to prepare a proposed rulemaking on demand response measurement and evaluation protocols and cost-effectiveness methods. We will, in the interest of clarity, direct agency staff to address the issue of revising the existing demand response goals in the upcoming proposed rulemaking.

B. Cost-Effectiveness Tests

Parties to this proceeding have expressed concern about issues of cost-effectiveness with regard to the program augmentations we consider here as well

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10 DRA Opening Comments at 9.

11 PG&E Reply Comments at 8.

as with existing demand response program activities. We have directed agency staff to hold workshops on cost effectiveness methods, elicit comments on draft measurement evaluation protocols, and recommend further action to the Executive Director of the Commission. Agency staff have made that recommendation and are drafting a proposed rulemaking for consideration by the Commission.

Following our direction in D.03-06-032, representatives from each of the IOUs and agency staff have been conducting measurement and evaluation studies on the demand response programs approved in these proceedings. Those studies have been very valuable to the utilities, other parties and the Commission as we work to improve program offerings to increase demand response and lower costs. These efforts should be continued.

In D.06-03-024, we authorized the Working Group 2 Measurement and Evaluation subcommittee to continue its work in providing oversight of demand response evaluation, and we continue that authorization for the program augmentations we approve here under the more appropriate name of the Demand Response Measurement and Evaluation Committee.

Because we believe it to be very important to fully monitor and evaluate the progress of these programs, we direct the IOUs to provide all data and background information used in monitoring and evaluation projects to Energy Division and the CEC, subject to appropriate confidentiality protections. In addition, we direct the IOUs to provide appropriate subsets of these data to vendors and academic researchers selected by the Commission or the CEC, such as the Demand Response Research Center, to conduct additional monitoring and evaluation projects, under appropriate confidentiality protections, as needed.

C. Use of Demand Aggregators

The Commission directed the utilities to identify opportunities to enhance their demand response programs by encouraging the participation of third-party demand aggregators. As one aggregator points out in relation to a particular program, "Aggregators can enlist customers who may be discouraged from participating due to program complexity, the short notification window, or the stringent penalties for non-performance…"[12]

TURN proposes that the utilities make better use of third-party contractors to implement demand response programs. TURN believes the utilities are not in the business of designing demand response programs and that third-party providers may be more creative and cost-effective in their efforts. SLVG makes similar comments.

We agree with the parties who suggest demand aggregators may encourage innovative and less costly demand response programs. We direct utilities to cooperate with demand aggregators to improve their demand response programs. We address several proposals below and state our intent to motivate utility use of third parties where sensible.

V. Summary of Utility Proposals

A. PG&E

In response to the August 9, 2006 ruling, PG&E proposes improvements to many of its existing programs and new programs that it expects will increase available load reductions by 235 MW by June 2007 relative to the 479 MW load drop the utility experienced in July 2006 when all programs were called. PG&E's

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[12] EnerNOC at 13.

proposals would increase potential load drop in 2008 by an additional 50 MW. PG&E also proposes stepping up its marketing efforts and making some programs more attractive by tailoring them to customer needs. New programs proposed by PG&E include an Auto DR program and a program to retrofit customer-owned back-up generation (BUG). On the basis of performance in July 2006, PG&E believes it can expect about 714 MW of load reduction in 2007 if its proposed programs are approved and implemented.

PG&E does not seek additional funding for the program improvements it describes, stating its intent to reallocate existing funds, and the possibility that it may seek additional funding at a later date. For example, PG&E states that it intends to file an application in November 2006 that will expand its AC Cycling program. A number of other proposals discussed in PG&E's August 30, 2006 are still in the conceptual phase and will be proposed formally through subsequent advice letters and applications.

The follow table summarizes PG&E's proposals:

Program	Proposed Augmentation	Cost Estimate	Incremental MW per year (2007-2008)
AC Cycling[13]	Begin full implementation in 2007.	2007: $7.5 M 2008: TBD	2007: 5 MW 2008: TBD
Auto DR	Convert pilot program to further develop automation and encourage the installation of enabling technologies for CPP customers using TA/TI funds. Additional $50/kW for a total of $300/kW TI incentive for auto DR technology.	$4.0 M	2007: 15 MW 2008: 15 MW
Back-Up Generators (BUGs)	A new program to convert diesel-powered back-up generators to dual-fueled diesel/natural gas.	$24 M	2007: 50 MW 2008: 50 MW
BIP and Nonfirm	Increase incentive payment for Option A: $8/kW for 100 kW to 500 kW reductions, $8.5/kW for 501 kW to 1 MW, and $9/kW for 1 MW or greater. Replace existing Option B option with new E-BIP option, which pays $500/MWh, with no capacity payment, no penalty for non-participation, 4 hours' notice, and called only when deemed prudent by PG&E. Available to aggregators. Re-open non-firm program to new-	$3.3 M	2007: 70 MW 2008: 25 MW

13 Budget and MW for only Year 2007.

Program	Proposed Augmentation	Cost Estimate	Incremental MW per year (2007-2008)
	customers for 2007.		
Demand Bidding Program (DBP)	Create "no-bid" option that does not require customers to enroll to be eligible for incentive payment. (No-bid option has lower incentives, requires 10% minimum reduction, has shorter event period, and is summer-only). Move day-ahead notification from 3:00 p.m. to noon. Allow Friday notification for Monday. Increase incentives, offer additional incentive for reductions during CAISO Stage 1 emergencies.	$7.5 M	2007: 25 MW 2008: 25 MW
Extend Business Energy Coalition (BEC)	Expand and expedite pilot program, which targets hard to reach customers. Also requesting seven-year extension.	TBD	2007: 25 MW 2008: 25 MW
Expanded TA/TI	Increase TA payment to $100/kW with cap of $100,000. Increase TI payment to $250/kW for equipment installation and an additional $50/kW for auto DR.	$10 M	2007: 10 MW 2008: 10 MW

Program	Proposed Augmentation	Cost Estimate	Incremental MW per year (2007-2008)
RFPs and Contracts	Issue an RFP for DR proposals for up to five summer periods to provide bidders a full opportunity to develop and propose innovative ways to increase DR. Bidders may include DR aggregators, PG&E customers, ESPs, and wholesale customers	$0.4 M	2007: 35 MW 2008: 35 MW
Admin & Marketing	Increase marketing efforts to encourage customers to sign up for existing and new DR programs.	$12 M	N/A
Online DR Enrollment	Customers can enroll in DR programs on-line.	$0.95 M	N/A
SPP Extension	Extend rate through June 2007, when the residential CPP rate will be made available.	$1.0 M	N/A
SCAPP (SF Power)	Extend 2006 deadline to June 2007 for recruitment of 1 MW to receive an additional $250,000 funding as approved in Amended Settlement. Institute peak load shifting and submeter aggregation programs.	$0	1 MW
CPP	Eliminate zones and call events based on system-wide average temperature. Earlier notification time.	$0	7 MW
Total		**$70.25 M**	**2007: 235 MW 2008: 285 MW**

B. SCE

SCE proposes some modifications to its existing demand response programs and proposes to implement a new Auto DR over two years, all by reallocating funds from existing programs. SCE recommends reallocating $300,000 of its existing budget to demand bidding so that it may increase the incentives. SCE estimates this effort would make up to 25 MW available in 2007.

At the workshop, SCE also explained several administrative changes it is making to some of its programs to make them more attractive to customers and thereby increase participation. SCE has offered other demand response program changes by way of advice letter.

The following summarizes SCE's program proposals:

Program	Proposed Augmentation	Cost Estimate	Incremental MW per year (2007-2008)
Auto DR	New program to use automatic equipment to facilitate activation of demand reductions during events. Recruit ten to twenty facilities to participate in fully-automated CPP or DBP. Use TA/TI funds to encourage the installation of Auto-DR. Increase incentive to $250/kW for energy management systems installed in conjunction with Auto-DR.	$1.79 M	10 MW
DBP	Increase incentive to $0.75/kWh for summer 2007 only. "Softer" trigger. Allow standing bids. Lower minimum bid from 200 to 100kW for aggregated accounts and from 50 to 30kW for individual participants. Allow online enrollment.	$0.3 M	25 MW
Total		**$2.09 M**	**35 MW**

C. SDG&E

SDG&E generally proposes modifying some programs to include "soft" triggers, which would provide SDG&E with discretion as to when to call an event rather than always calling for load reductions according to pre-established criteria. SDG&E wishes to standardize trigger mechanisms across programs, and also align incentives across programs to reflect the value of load reductions in each. It plans to simplify enrollment in ways that accommodate customer interests, continue the Smart Thermostat program into 2007, improve opportunities for load aggregator participation and introduce a new program targeted at permanent load shifting that would take advantage of TA/TI funds. The program changes it seeks here would not affect SDG&E's total authorized budget and program costs would come from existing budget item.

The following summarizes SDG&E's program proposals:

Program	Proposed Augmentation	Cost Estimate[14]	Incremental MW per year (2007-2008)
C&I 20/20 (Peak Day Credit) Program	Extend changes approved for 2006 program to 2007, "Softer" trigger; set maximum # of events to 15.	$55,627	2007: 20 MW 2008: 14 MW
DBP	Merge DBP and E-DBP, increase incentives to $.50/kWh for Day-Ahead and $.60/kWh for Day-Of, use enrollment cards in place of contracts; allow standing bids.	$0	2007: 6 MW 2008: 6 MW
BIP	Reduce penalties by 25%.	$0	2007: 2 MW 2008: 2 MW
Residential Smart Thermostat	Continuation of program (2 MW), currently scheduled to terminate at the end of 2006, through 2007.	$410,264	0 MW
AC Cycling (Summer Saver)	Add new options: 100% cycling for residential and 30% cycling for commercial, include pool pumps and hot water heaters, include weekends	(confidential)	2007: 18 MW 2008: 4.7 MW
CPP	"Softer" trigger, increase maximum # of events to 15.	$34,210	2007: 8 MW 2008: 6 MW
TA/TI	Extend 2006 TI payment of $250/kW through 2007.	Embedded in other DR programs	
Peak Load Management	Promote technologies which permanently shift peak	N/A	

[14] Implementation cost are the difference between the Total Program Budget filed in August 30, 2006 Augmentation proposal and the Total Program Budget in Settlement approved in D.06-03-024.

	demand as subset of TA/TI.		
Program	**Proposed Augmentation**	**Cost Estimate**[15]	**Incremental MW per year (2007-2008)**
Auto DR	Promote automatic demand reduction technologies (subset of TA/TI).	N/A	
Third-Party Aggregators	Offer aggregators more opportunity for participation (BIP, CBP and all-source RFO).	Embedded in other DR programs	
In-home display	Pilot program of 300 residential customers to measure customer behavior changes with real-time energy usage information.	$430,836	N/A
Water Agency	DR programs targeted for water agencies, covered by separate AL.	Advice Letter filing by 10/31/06	
TOTAL		**$500,101**	**2007: 54 MW 2008: 32.7 MW**

15 Implementation cost are the difference between the Total Program Budget filed in August 30, 2006 Augmentation proposal and the Total Program Budget in Settlement approved in D.06-03-024.

VI. Demand Response Proposals

A. Proposals Applicable to Multiple Utilities

1. BIP, Non-Firm Service Program, and I-6

a) PG&E BIP and Non-Firm Program

The BIP is a demand response program offered to large customers who receive monthly incentive payments as compensation for their willingness to curtail load within 30 minutes during a Stage 2 power emergency. BIP customers that fail to curtail load according to the tariffs face substantial penalties. PG&E's Non-Firm Service Program is similar to the BIP program in that it provides incentives to large customers who agree to curtail load during a Stage 2 event. This program is no longer open to new subscribers. In D.05-04-053 the Commission ordered the utilities to transition existing Non-Firm rates into BIP.[16] PG&E has proposed such a transition in its 2007 General Rate Case Phase 2, A.06-03-005, which would be effective January 1, 2008. On August 24, 2006 the Commission approved staff Resolution E-4018 , which granted PG&E's request to temporarily allow new customers to sign up for the Non-Firm program for 2006, as long as the customers enrolled by September 15, 2006. The question of whether 2006 enrollees will be allowed to remain on the program in 2007 was deferred to this proceeding. The resolution rejected PG&E request to reopen the program for 2007, and invited PG&E to submit the request again in this proceeding.[17]

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[16] D.05-04-053 at 80.

[17] Resolution E-4018 at 11.

PG&E proposes increasing BIP incentive payments as load reductions increase to encourage customers to maximize commitments of capacity. Current incentive payments are $7.00/kW of Potential Load Reduction (PLR), and PG&E proposes the following monthly incentives per kilowatt (kW) committed:

PLR	Monthly Dollars per kW-hr PLR
100 kW to 500 kW	$8.00/kW
501 kW to 1 MW	$8.50/kW
1 MW or greater	$9.00/kW

PG&E also believes that increasing incentives will ease the transition of customers from the Non-Firm program to BIP.

PG&E proposes to eliminate its BIP Option B, which permits customers to receive a longer notification period and shorter event duration in return for a smaller incentive. PG&E states no customer has signed up for Option B. PG&E instead proposes to introduce a new Option B that the utility says is modeled on successful programs in the NYISO and PJM control areas. Under the new Option B, participating customers would have the opportunity to receive a minimum energy payment during CAISO Stage 2 or 3 events or during local reliability emergencies if the program is called by PG&E. Customers would have four hours notice, would not be penalized for non-performance, and would not receive any capacity payment.

PG&E would set the minimum incentive payment at $0.50/kWh until the CAISO has implemented locational marginal pricing. Once locational marginal pricing is implemented, customers will be paid the higher of $0.50/kWh or the locational marginal price in the CAISO real time imbalance market that applies to the geographic location of the customer.

This option would be available to individual customers as well as aggregators. Aggregators may be paid a fee based on the amount of capacity they sign-up for. PG&E notes that aggregators are active in similar programs offered in the NYISO and PJM areas, and aggregators existing relationships with national companies could improve participation. PG&E is opposed to aggregator participation in the BIP Option A due to its similarities to the Capacity Bidding Program (CBP), which is open to aggregators.

PG&E believes that the success of programs similar to the proposed new option in other parts of the country indicates the potential for success in its territory. The utility projects that over a two to four year period the program could sign up as much as 100 to 200 MW.

PG&E also proposes to reopen its Non-Firm program in 2007. PG&E observes that when called in July 2006, participants' load reductions exceeded subscribed load.

PG&E estimates that its recommended changes to the BIP and Non-Firm programs would yield an additional 70 MW in 2007 and 25 MW in 2008 at an incremental cost of $2.5 million in 2007 and $0.8 million in 2008.[18]

CLECA/CMTA support PG&E's proposals to expand participation in BIP and reopen the Non-Firm program.[19] Aglet objects to increasing funding for BIP and reopening the Non-Firm program, raising general concerns about cost-effectiveness.[20] DRA recommends holding hearings on PG&E's proposed BIP Option B but does not explain the factual controversy that would be addressed in hearings. DRA opposes reopening the Non-Firm program because it is duplicative of BIP, and a temporary re-opening of the Non-Firm program

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18 PG&E Proposals at 36.

19 CLECA/CMTA Opening Comments.

20 Aglet Opening Comments at 4-5.

may confuse customers.[21] The demand aggregators would like to see PG&E's existing BIP Option A opened to aggregator participation. EnerNOC asserts that demand aggregators can bring in additional customers.[22]

We adopt PG&E's proposed increased incentive payments for BIP Option A as proposed. We agree with PG&E that increasing incentives and offering larger incentives for larger capacity commitments could attract more and larger capacity commitments. We also authorize PG&E to close the existing BIP Option B and adopt the new Option B proposed by the utility. The incentive rate for the proposed new Option B should be set at $0.60/kWh to be consistent with the day-of DBP incentive discussed below. The new Option B could be attractive to additional customers, and the fact that there are no ongoing payments to customers alleviates potential cost-effectiveness concerns.

We also require PG&E to open its Option A to third-party aggregators.

We share DRA's concerns that reopening Non-Firm program could confuse customers, especially since the program could be ended as soon as January 1, 2008. We prefer multi-year program changes that allow customers to plan and make investments that could increase their demand response on an ongoing basis. We therefore deny PG&E's request to permit new customers to sign-up for the Non-Firm program in 2007.

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[21] DRA Opening Comments at 12-13.

[22] For example, EnerNOC Reply Comments at 3-4.

b) SDG&E BIP

SDG&E wishes to reduce the penalties for its BIP in order to attract more customers. Currently, Option A subscribers receive an incentive payment of $7/kW per month and are penalized $6/kWh for failure to reduce load, and Option B subscribers receive an incentive payment of $3/kW per month and are penalized $2.50/kWh for failure to reduce load. SDG&E proposes reducing the penalties for each option by 25 percent to $4.50/kWh for Option A and $2.50/kWh for Option B.[23]

SDG&E also proposes to add additional triggers to the program that would allow the program to be triggered during a CASIO Stage 2 Alert and when extreme temperature conditions impact system demand. Additionally, the utility would like to change BIP's Rule 29 language so that incentive and penalty payments for aggregated load will be calculated in aggregate using individual customer meter data. Also, SDG&E proposes to eliminate the BIP once SDG&E's new CBP is adopted and proposed to transfer all BIP customers to the CBP.[24,25]

DRA supports SDG&E's proposal to attract more participants in BIP by reducing penalties.[26] EnerNOC supports SDG&E's proposed changes to Rule 29, but opposes the utility's plan to eliminate BIP and transfer participants to the CBP because BIP and CBP will appeal to different customers. EnerNOC

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[23] SDG&E Proposals at 17-18.

[24] SDG&E Proposals, Attachment 1 at 23-24.

[25] Resolution E-4020, adopted by the Commission on October 19, 2006, approved SDG&E's CBP.

[26] DRA Opening Comments at 12.

additionally recommends that SDG&E allow aggregators to enroll customers with load reductions less than 100 kW and make monthly incentive payments based on the difference between aggregated Firm Service Level (FSL) and aggregated Monthly Average Peak Demand (MAPD).[27]

We will authorize SDG&E's proposal to reduce penalties, adopt additional triggers and change Rule 29. We also direct SDG&E to permit aggregators to sign up customers with less than 100 kW as long as the aggregated load exceeds 100 kW and to make monthly payments based on aggregated FSL and MAPD. We believe these changes will increase customer participation in BIP. We deny SDG&E's proposal to close the BIP program and transfer customers to CBP. BIP was created as a statewide program, in part so that it attracts customers in multiple service territories. We believe the program should be continued on a statewide basis.

c) SCE I-6 and BIP

SCE is opposed to reopening its I-6 interruptible program since customers can sign up for BIP, which offers similar incentives. SCE has proposed a new 15-minute I-6 and BIP option through Advice Letter 2032-E. The Commission has approved a staff resolution that adopts this option. Therefore, we do not discuss parties' comments on the 15-minute option here.

In response to the Administrative Law Judge's (ALJ) inquiry about whether aggregators should be able to participate in various demand response programs and a proposal by EnerNOC, SCE explains that its interruptible programs, I-6 and BIP, are not well-suited to aggregator participation. SCE

[27] EnerNOC Opening Comments at 14 and Reply Comments at 4-5.

believes that quick and effective response to calls for load reduction would be difficult and more complex if aggregators were involved, partly because SCE notifies and monitors customers through a particular communications network. It believes aggregators would complicate the program by introducing alternative technologies. SCE does suggest, however, that it might propose a new interruptible program, open to aggregators, in the near future.[28]

The CAISO questions SCE's reluctance to collaborate with aggregators and suggests that some of subscribed load lost since the pre-energy crisis period could be regained by engaging aggregators.[29] EnerNOC also refutes SCE's assertion that aggregator will complicate the program without bringing any benefits. EnerNOC notes that it has demonstrated in northeastern markets that it can notify and monitor customer performance rapidly and in a variety of circumstances. SCE would only have to make minor changes to the program to allow for aggregation of portfolios.[30]

We agree with the CAISO and EnerNOC that allowing aggregators to participate in the BIP could increase available demand response. We therefore direct SCE to file an advice letter proposing changes to BIP that permit aggregation, similar to the SDG&E's BIP program.

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[28] SCE Opening Comments at 3-4.

[29] CAISO Reply Comments at 5.

[30] EnerNOC Reply Comments at 5-6.

d) Customer Window to Adjust Firm Service Level

Customers may want to increase or decrease their firm service level given the changes to PG&E's and SDG&E's BIPs adopted in this decision. PG&E and SDG&E are required to give customers 30 days from the date this decision is adopted to adjust their firm service levels for 2007.

2. Demand Bidding Program (DBP)

The DBP permits subscribers to bid the amount of energy they are willing to drop in case of a demand response event. Subscribers receive payment only when the program is triggered. Because no incentive is paid unless an event is called, subscribers face no penalties if they fail to reduce demand.

a) PG&E

PG&E proposes a number of changes to its DBP program as follows:

No-bid Option – PG&E proposes a "no bid" option to the DBP, which provides that that customers do not have to pre-subscribe to the program but may participate only if an event is called. Customers must provide a minimum 10% demand reduction. Incentives would be smaller and the event window would be narrower than those for other DBP options.

Trigger Change – PG&E proposes changing the DBP trigger because it believes program events are triggered even when there are sufficient reserves. The proposed "soft" trigger would correspond to system conditions rather than automatically adhering to preset criteria.

Bid Window – PG&E would widen the bid window to give customers additional time to make bids. Customer feedback has indicated that a wider bid window would make it easier for customers to participate, so this change would result in increased customer participation.

Incentive Increase – PG&E proposes to increase its "bonus adder" to $.20/kWh above the market price for energy. PG&E does not support changing the incentive to a flat rate structure as recommended by DRA because such a change would require remarketing and could be detrimental to 2007 program performance.[31]

CAISO Alert Bids – PG&E proposes adding an additional $0.10/kWh to the incentive when a DBP event is called during a CAISO Stage 1 or higher alert. Also during CAISO alerts, PG&E would pay customers for all load reductions, including that in excess of the normal 150% cap. These added incentives are intended to increase customer response during CAISO emergencies.

Budget – PG&E proposes to shift $3.743 million to its DBP program to reflect the cost of these changes, which its estimates will increase load reductions by 25 MW in 2007.

Aglet is opposed to increasing funding for the DBP because the costs exceed the payments that would be required for new generation.[32] TURN raises concerns that there is little evidence to suggest that any of the utilities' DBP programs provide any demand response benefits due to the flawed baseline. TURN also suggests there is information in a 2006 report by Quantum Consulting indicating that the program may increase environmental pollution as subscribers turn on backup generators at their premises.[33]

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31 PG&E Reply Comments at 9.

32 Aglet Opening Comments at 5 and Reply Comments at 2.

33 TURN Opening Comments at 15-16.

DRA is not opposed to PG&E's proposal to increase incentives but suggests that the program could be made more customer-friendly by adopting a flat incentive such as that proposed by SCE and SDG&E. DRA does not support adopting the no-bid option at this time because the option could attract free riders.[34] ECI and SVLG support PG&E's proposal to increase the bonus incentive.[35]

b) SDG&E

SDG&E proposes to join the Emergency DBP – a day-of reliability program – with the DBP program. SDG&E believes that providing both day-ahead and day-of options within the same program will make it easier to administer the program. SDG&E would increase incentives to $.50/kWh for the day-ahead program and $.60/kWh for the day-of program. Customers would be paid for reductions that are equal to or greater than the amount bid, with no limit. SDG&E also proposes several program changes designed to make it easier for customers to participate in DBP such as permitting customers to make standing bids, and simplifying enrollment.

Aglet is opposed to increasing SDG&E's DBP incentives.[36] TURN's critique of the DBP program in general applies equally to SDG&E's. DRA supports SDG&E's flat incentive proposal but prefers a slightly lower incentive

[34] DRA Opening Comments at 10.

[35] ECI Opening Comments at 2 and SVLG Reply Comments at 2.

[36] Aglet Opening Comments at 7.

of between $0.40/kWh and $0.45/kWh. DRA is concerned that SDG&E's proposed standing bid could encourage free riders.[37]

c) SCE

SCE proposes several changes to its DBP as follows:

Incentive Increase – SCE proposes increasing the incentive for summer 2007 to $0.75/kWh, believing the higher amount is required to motivate customer participation. SCE reports that its proposed incentive increase reflects what its customers say they require in order to offset the cost of reducing load.

Trigger Change – SCE proposes to modify the DBP trigger so that the DBP program is called only when needed, not simply in response to pre-determined criteria.

Program Administration – SCE proposes simplifying certain program elements in ways that should encourage participation without increasing program costs. For example, SCE proposes to streamline enrollment procedures, decrease the size of the minimum bid, and permit customers to make standing bids.

Aglet does not support increasing SCE's DBP incentives.[38] TURN's general critique of the DBP program in general applies equally to SCE's. DRA agrees with SCE's emphasis on making the program more customer friendly by using a flat-rate incentive, but believes that SCE's proposed incentive level is too

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37 DRA Opening Comments at 11.

38 Aglet Opening Comments at 6.

high. DRA instead recommends an incentive level between $0.40/kWh and $0.45/kWh.[39] ECI and SVLG support SCE's proposal to increase incentives.[40]

d) Discussion

We generally support the proposals by the utilities and other parties to make the DBP more customer-friendly in order to increase program participation and demand response. Accordingly, we approve the soft triggers proposed by PG&E and SCE and direct SDG&E to adopt a similar trigger; we approve PG&E's proposal to widen the bidding window, and direct SDG&E and SCE to do the same; and we approve the enrollment simplification proposed by SDG&E and SCE, and direct PG&E to do the same. SCE's and SDG&E's proposals to allow standing bids are also approved.

We agree with SDG&E and SCE that replacing the market based incentive with a flat incentive would make the program easier to understand and can facilitate simplifying enrollment. Therefore, we direct all three utilities to adopt a flat rate incentive. We will approve a flat incentive payment of $0.50/kWh for day-ahead calls and $0.60/kWh for day-of calls when a CAISO alert of Stage 1 or higher is called. The higher incentive levels should increase program participation and demand response. We also direct all three utilities to offer a day-of program similar to that proposed by SDG&E.

We do not approve PG&E's proposed no-bid program. It is unclear how this program would contribute to energy reductions. Since a customer who subscribes makes no commitment and its rates are not affected unless it

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39 DRA Opening Comments at 10-11.

40 ECI Opening Comments at 2 and SVLG Reply Comments at 2.

voluntarily reduces load, it is not clear why this program would be more attractive to customers than the existing program. Some participants may be free riders if they are paid for demand reductions that were undertaken for business reasons rather than as program participants. The program may permit an expenditure of funds for energy reductions that would have been undertaken anyway. Accordingly, we reject PG&E's proposal for a no-bid option.

3. Air Conditioning (AC) Cycling Programs

AC cycling provides a utility remote air conditioning controls at residential customer premises. On August 15, 2006, President Michael R. Peevey issued an Assigned Commissioner's Ruling (ACR) in R.05-12-013 and R.06-02-013 directing SCE, PG&E, and SDG&E to evaluate installing additional AC cycling in their service territories for the summer 2007 season. The ACR was served on the service list in this proceeding. The Commission considered SCE's AC cycling proposal on October 19, 2006 in Resolution E-4028. PG&E and SDG&E made proposals in this proceeding.

a) PG&E AC Cycling

PG&E states its intent to use existing demand response funding to expand the pilot AC cycling program that was agreed to by the utility in the Amended Settlement adopted by D.06-03-024. The utility had agreed to sign up 2,000 total residential customers during 2007 and 2008, which would equate to about 2 MW. PG&E is now proposing to significantly expand the program for 2007 and fully roll-out the program starting in 2008.

PG&E proposes to commit $7.5 million and sign up about 5,000 customers by June 2007, with sign-ups continuing throughout the summer. That translates to 5 MW of load reduction by June 2007. The utility's program would include both a switch based direct load control (DLC) option and a *Smart*

Thermostat option. Customers would have the option to choose from several DLC or *Smart Thermostat* options. The general program framework is described in the utility's August 30, 2006 filing.

PG&E's budget includes contractor costs, marketing and advertising, early signup incentives, consulting fees, labor, and one-time costs associated with setting up a new program including billing system modifications, creation of web enrollment, and program evaluation. In reply comments the utility notes that the requested funding could fund the installation of up to 15,000 switches, which roughly equates to 15 MW, if the Commission approves the future operating costs in the utility's yet-to-be-filed application. If the full deployment application is approved then the amount of money that the utility needs from the 2006-2008 demand response budget would be much less than $7.5 million.[41]

PG&E intends to file an application in November 2006 proposing a multi-year AC cycling program. In the meantime the utility requests that the Commission authorize its rollout strategy and general program design, authorize the shifting of $7.5 million, and provide for expedited approval of its advice letter implementing the 2007 program.

Aglet, CLECA/CMTA, and EUR generally support increasing funding for PG&E's AC cycling program.[42] EUF argues that "all possible, cost effective AC Cycling programs should be implemented for Summer 2007 due to

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41 PG&E Reply Comments at 4-5.

42 Aglet Opening Comments at 4.

AC Cycling's proven benefits.[43] CLECA/CMTA support PG&E's plan to initiate an AC cycling program and recommends that cost-effectiveness should be analyzed over the long-term.[44]

DRA states that the Commission should focus on reliability type programs first, and notes that SCE's AC cycling program is the most-subscribed reliability program available to residential and small commercial customers.[45] DRA does not, however, take a position on PG&E's AC cycling proposal. Instead DRA says it will provide detailed comments once PG&E files its detailed proposals.[46]

TURN conditionally supports PG&E's AC Cycling proposal.[47] However, TURN believes PG&E's proposal appears to be overly expensive and observes that SDG&E has a third-party AC Cycling arrangement that would cost $350,000 per year for 5 MW and $7 million per year for 100 MW. TURN also raises concerns that PG&E is seeking funding authority for a program for which there are very few details.[48]

We appreciate PG&E's response to our call for AC cycling program proposals and understand the difficulty of creating an elaborate plan on such short notice. While we generally prefer demand response programs that engage

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43 EUF Opening Comments.

44 CLECA/CMTA Opening Comments.

45 DRA Opening Comments at 8-9.

46 Id. at 14.

47 TURN Opening Comments at 6.

48 Id. at 6-7.

customers in managing their energy usage, AC cycling has proven to be a valuable reliability resource in SCE's service territory and is beginning to play an important role in SDG&E's territory. AC cycling can also result in concrete load reduction capability in PG&E's service territory. We approve in concept PG&E's proposal to install 5,000 switches in 2007 using the existing demand response budget and subject to advice letter review. We support PG&E moving forward with an AC cycling program for 2007 but need additional information to review the proposal. In the advice letter, PG&E should provide detailed budget information including the costs of installing the switches, incentives, and any other costs. We encourage parties interested in this proposal to review the advice letter. PG&E may move forward with its proposed RFP for competitive bids.

We will address PG&E's long-term program costs when we have more information about its proposed program which can provide parties and the Commission a reasonable opportunity to evaluate it.

b) SDG&E Summer Saver Program

SDG&E proposes to expand its Summer A/C Saver program to include pool pumps and electrical water heating, renaming the program the Summer Saver Program. It would also provide residential customers a new 100% cycling option, in addition to the current 50% cycling option. Non-residential customers would be offered a new 30% option, in addition to a 50% option. Customers will also be able to sign up for weekend events. A third party, Comverge, administers this program and has agreed to the program changes.

Aglet supports SDG&E's proposed changes.[49] DRA thinks that SDG&E's proposed changes are reasonable but reserves judgment until DRA has had an opportunity to review the contract with Comverge which will be included in SDG&E's advice letter.[50]

TURN generally supports this program but raises concerns that the requirement that customers make 100% of their air conditioning available for cycling may reduce customer acceptance of the program. TURN also believes SDG&E's website on this program does not provide enough information to motivate customer interest.[51]

The additional cycling options SDG&E proposes appear reasonable and likely to improve program participation. Therefore, we adopt them. The Commission previously approved contract amendments to include pool pumps and electrical water heating in Resolution E-3913. We will not reconsider that approval here. Including pool pumps and electrical water heaters in SDG&E's program could provide valuable information if the Commission or any utility considers these programs in the future. We also direct SDG&E to consider improvements to its website that would provide better customer information.

4. Demand Response Request for Proposals (RFP)

PG&E proposes to issue an RFP for demand response proposals for up to five summer periods. PG&E estimates that the innovative ideas that result

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[49] Aglet Opening Comments at 6.

[50] DRA Opening Comments at 15.

[51] TURN Opening Comments at 8-9.

from the RFP could result in PG&E signing contracts for up to 35 MW of additional load reduction in 2007 and 2008.

The RFP would focus on resources that can be provided in CAISO Stage 2 conditions for the summers of 2007 and 2008. Customers, aggregators, energy service providers and wholesale PG&E customers can bid. PG&E proposes to pay for the costs of any contracts through the Energy Resource Recovery Act (ERRA) account. It would submit contracts to the Commission by way of expedited advice letters. PG&E would spend $200,000 from its existing demand response budget in each of 2007 and 2008 for potential signing bonuses and customer incentives.

PG&E points to RFPs run by SDG&E and utilities in other states as examples that PG&E would build on.

SDG&E describes an all source Request for Offers that it recently completed which specifically requested demand response capacity offers. The utility is currently evaluating the conforming offers and expects to complete contracts by mid-November and bring the contracts to the Commission for approval. The six conforming bids represent a total of 50 MW of capacity.

In response to parties comments SCE proposes either initiate an RFP or seek bilateral arrangements to capture innovative demand response proposals. SCE suggests that it would file an advice letter to request Commission approval and any additional funding once specific programs have been selected.[52]

[52] SCE Reply Comments at 2-3.

Aglet and EnerNOC recommend that PG&E and SCE be directed to pursue RFPs and bilateral demand response contracts.[53] DRA supports cost-effective demand response contracts identified through RFPs and bilateral arrangements.[54] TURN is concerned that the RFP process proposed by PG&E is too open-ended, and the advice letter process would not permit sufficient review.[55]

As with many parties who commented, we believe that seeking proposals directly from customers and aggregators could potentially unleash innovative and cost-effective demand response technologies and activities. On the other hand, we do not here pre-authorize yet-to-be identified contracts or specific cost-recovery mechanisms. Instead, we direct PG&E and SCE to move forward with their proposals to run an RFP or seek bilateral contracts. We agree with TURN that the advice letter process would not provide the Commission and intervenors an opportunity to evaluate proposals. Each utility should file an application with the Commission requesting approval for specific contracts by February 28,, 2007. Due to the emphasis on getting demand response capacity ready for the summer of 2007, the Commission will consider the applications expeditiously.

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53 Aglet Opening Comments at 2 and EnerNOC Opening at 19.

54 DRA Reply Comments at 8.

55 TURN Opening Comments at 11.

5. Technical Assistance/Technical Incentives (TA/TI)

TA/TI funds can be used to provide energy audit services for customers and encourage customer adoption and installation of demand response measures. TA/TI can facilitate customer participation in various demand response programs.

PG&E proposes to increase the TA incentive level to $100/kW with a maximum incentive of $100,000, and increase the TI incentive to $250/kW, with an additional $50/kW for Auto DR. PG&E requests the flexibility to use funds to cover direct customer incentives, customer labor and site assessment support and the use of multiple technical and systems integration contractors, in addition to the contractor costs.[56]

SDG&E proposes retaining the 2006 incentive payment of $250/kW into 2007 for new technology installations. SDG&E proposes to establish a subset of the program focused on permanent load shifting. SDG&E is developing performance measurement criteria and a list of qualifying equipment for its permanent load shifting program.

SCE proposed to increase the available incentive from $100/kW to $250/kW specifically for Auto Demand Response (DR) technologies.

We believe that increasing TA and TI incentives will increase customer participation in demand response programs. We approve PG&E's to increase its TA incentive level to $100/kW. We also adopt PG&E's proposal to increase TI incentives to $250/kW and $300/kW for Auto DR. We direct SCE and SDG&E to implement to same higher TI incentives. We also agree with

[56] PG&E Reply Comments at 11.

PG&E that allowing TA/TI funds to cover direct customer expenses will help the program, so we adopt PG&E's requested flexibility for all three utilities.

6. Automated Demand Response (Auto DR)

Auto DR, a research program managed by the Demand Response Research Center (DRRC), is designed to link facility energy management control systems with external utility-generated price or emergency signals. The use of this technology is integrated with various existing utility demand response programs, such as the critical peak pricing program.

In response to the Assigned Commissioner's ruling, PG&E proposes to spend $2 million a year in 2007 and 2008 to implement Auto DR using TA/TI funds. PG&E expects the participation of about 15 MW in each year. PG&E's incentives would apply to software, hardware, and programming in addition to equipment. PG&E raises concerns about full-scale rollout and wide customer acceptance and the availability of communication devices. It proposes third-party implementation as a way to ease these potential problems. PG&E would also increase the TI incentive to $300/kW and expand the use of TA/TI funds to include direct customer incentives, customer labor and site assessment support and the use of multiple contractors for different elements of the implementation. DRA objects to an increase in incentives until PG&E has presented the Commission with a detailed implementation plan.

SCE currently has a pilot program and proposes to increase its Auto DR efforts with a 2007 budget of $1.79 million with a goal of commercializing Auto DR products in the near future. SCE would focus for the first year on identifying "key opportunities" and evaluating effectiveness and customer response. They would implement the program by working with the Demand Response Research Center (DRRC) to "bring functionality to a commercial level" using third party contractors. The program would provide automated notifications for participants in the CPP and DBP programs. It would increase the existing technology incentive to $250/kW with an expectation of motivating about 10 MW of additional load reductions.

SDG&E would implement its Auto DR through existing Emerging Technologies Program using the TA/TI incentive structure with incentives of $250/kW. DRA raises concerns that SDG&E has failed to present a specific implementation program.

When we directed the utilities on August 22nd to add Auto DR to the list of program elements to be included in their August 30th filings, we expected the proposals to lack some detail due to the short time available before the filing date. After reflecting on the variety of ideas proposed and concerns raised in comments, we provide some additional guidance. We approve these proposals—with some conditions—but direct the utilities to present detailed implementation plans to Energy Division as soon after this order is adopted as feasible. We specifically approve TI funds for $250/kW for all three utilities, as proposed by SCE and SDG&E but deny PG&E's request to increase their incentive to $300/kW. However, we do approve PG&E's request to expand the use of TA/TI funds to include customer costs and customer incentives for all three utilities and direct SDG&E and SCE to do the same. We also require the utilities to file proposals by October 31st, 2007 for continuation or modification of their Auto DR programs.

We have high hopes for Auto DR in facilitating demand response, but agree with PG&E's concerns about customer acceptance. We also agree with SCE's concern that additional pilot testing of the technology among a broad group of customers is warranted. Both of these concerns would point to a cautious approach; however, we also believe that we should maximize the impact of Auto DR for next summer. To resolve this apparent conflict, we direct the utilities to work with the DRRC to develop implementation strategies that will provide a high level of quality control as this technology goes through the early stages of commercialization while at the same time identifying key opportunities for maximizing the demand response impact. This may require focusing on building and customer types similar enough to the DRRC pilot participants that the shed strategies and technology installations are proven and relatively quick and easy to implement. It also may require that the programs focus on customers who can minimize the transaction costs involved in implementation and approval, such as chain stores where decision-making is centralized and where implementation strategies are, for the most part, replicable. We also have concerns, especially in light of the increased incentives being approved here, that customers receiving these incentives be obligated to provide demand response during critical events. If the utilities intend to provide Auto DR to customers participating in the DBP program, they should describe in their detailed proposals how those customers will be obligated to provide load reductions on critical days.

In their detailed implementation plans, each utility should describe in detail how they plan to work with the DRRC to take advantage of the knowledge they have gained in developing and pilot testing shed strategies and automated communications. Second, the utilities should each describe how they intend to train and monitor the third-party contractors implementing the program for quality control and customer satisfaction. Third, the utilities should describe how the TA/TI funds will be used for Auto DR. Fourth, the plans should include proposals for measurement and evaluation that provide real-time feedback to the program implementers as well as documentation of program impact and collection of information that will inform development of a long term commercialization strategy. Finally, the implementation plans should provide detailed budgets identifying administrative, evaluation, and incentive costs.

7. Permanent Load Shifting

Permanent load shifting occurs when a customer moves energy usage from one time period to another on an ongoing basis. Existing time-of-use (TOU) rates encourage some permanent load shifting because customers can reduce their energy bills by shifting load from peak periods when rates are higher to off-peak periods when rates are lower. In some cases, investment in load shifting technologies can enable greater amounts of load shifting. Examples of permanent load shifting technologies include thermal energy storage, batteries, and the pumping and storage of water. Currently, customers do not have access to incentives from the utilities to lower the cost of installing permanent load shifting technologies, other than TOU rate differentials. The technologies are generally not considered energy efficiency programs if they do not reduce overall energy consumption. At the same time, they are generally not considered demand response programs if they are not dispatchable or price responsive on a day-ahead or day-of basis. Nevertheless, load shifting may reduce the need for capacity investments, reduce the likelihood of shortages during peak periods and lower system costs overall by reducing the need for peaking units. All three applicant utilities have stated their support for load shifting programs as a way of improving system stability and reducing system costs. SCE and PG&E state an interest in proposing permanent load shifting programs before the end of the year. TURN and the CAISO express strong support for such programs generally although both raise the concern that load shifting does not represent a dispatchable form of capacity and urge the Commission's policies and programs should be designed with that concern in mind. DRA supports load shifting but believes there are many issues that deserve exploration, such as what would constitute a "permanent" load shift, how incentives should be paid, and how to avoid free riders. Other parties advocate for an allocation of funds to specific programs, which are discussed below.

PG&E and SDG&E recommend that permanent load shifting be eligible for TA/TI funding, but they do not support the creation of a special TOU rate. SCE generally supports permanent load shifting as demand response and indicates it will provide a specific proposal for the Commission to consider.

a) Ice Energy Proposal

Ice Energy proposes a specific load shifting program that would promote installations of ice storage air conditioning, a technology that creates and stores ice during off-peak periods so that air conditioning may be provided during peak periods with reduced electricity demand. The product Ice Energy proposes is referred to as "Ice Bear" and would be installed mostly in medium to large commercial buildings such as "big box" retail outlets. Ice Energy proposes upfront incentive payments for installation and ongoing incentive payments included in utility tariffs. Ice Energy proposes a program budget of $25 million for 2007 and estimates up to 12 MW of on-peak demand reduction. Over 15 years, it estimates 100 gigawatt-hours of peak energy would be shifted to off-peak periods and 15 gigawatt-hours of energy would be saved. Ice Energy provides evidence that the technology has been successfully applied in other utility territories, both within California and in other states.

b) Water Agency Proposal

D.06-03-024 directed the applicant utilities to work with the state's water agencies to develop demand response products that would be cost-effective and attractive to water agencies. It directed the utilities to file advice letters to implement such programs in October. In this phase of this proceeding, ACWA reports that its client water agencies are unlikely to take advantage of the utilities' proposals. Following an inquiry to the ALJ, ACWA filed comments that explain the types of water agency operations that might be amenable to demand response programs and include proposals for water agency demand response programs.

ACWA believes water agency programs could provide up to 30 MW of demand reduction. It estimates an annual cost of $2.9 million split between the three utilities – 45% each for SCE and PG&E and the remaining 10% for SDG&E. Incentives would be up to $85/kW with no energy payment and each program would be open to aggregators and be technology-neutral. ACWA proposes two specific programs, one that would shift peak usage permanently and the other that would reduce demand during a utility event, similar to the CPP program. ACWA provides illustrative tariff language for these programs. It states the utilities must offer the programs by January 2007 for water agencies to take advantage of them in time for summer peak in 2007.

On November 3, 2006 PG&E, SDG&E, and SCE filed a Joint Motion requesting approval of a program called the "Statewide Water Agency Program Proposal," which is intended to comply with the Amended Settlement approved in D.06-03-024.

c) Discussion

We are interested in pursuing permanent load shifting opportunities in time for the summer of 2007. These types of programs may reduce energy use during critical periods and in some cases conserve energy overall. While we defer the issue of how this or other permanent load shifting technologies should count toward demand response goals, we do recognize that new installations of permanent load shifting technologies will accomplish our goal of reducing peak demand for summer 2007 and so wish to encourage the IOUs to pursue permanent load shifting by allowing the use of TA/TI funds toward offsetting the initial costs of installation.

Ice Energy's proposal is interesting. However, we do not support allocating $25 million to a specific company or technology, such as the Ice Energy proposal, but prefer to initiate a more generic process.

Accordingly, we direct the utilities to pursue RFPs and bilateral arrangements by which they can solicit five-year proposals from third parties for permanent load shifting that can be implemented by summer 2007. We do not specify a preference for any particular technology, but the IOUs should consider cost-effectiveness, ease of implementation, the amount of load shifting that can be obtained by the summer of 2007, potential for growth and expansion, and the reliability of the technology. Each IOU is directed to file an advice letter with their proposals by February 28, 2007. PG&E, SDG&E, and SCE are authorized to shift up to $10 million, $4 million, and $10 million respectively of their existing demand response budgets, which is roughly in line with the size of the program proposed by Ice Energy.

d) Discussion of Water Agency Proposals

We will not address the ACWA proposal and Joint Motion of the utilities in this decision. Instead the Assigned Commissioner will respond to the Joint Motion and ACWA proposal in a subsequent ruling.

The Commission strongly supports developing demand response programs that are tailored specifically toward water agencies. The Energy Action Plan II explicitly identified reducing water supply system electric load during peak hours as a key action.[57] We intend to implement that key action in part by facilitating the development of water agency demand response opportunities by the summer of 2007.

B. PG&E Proposals and Budget

1. Large Customer CPP Program

The E-CPP is available to customers on time-of-use rates with maximum demand greater than 200 kW. Subscribers receive a discounted rate for summer usage except when a critical peak event is called at which time a customer is levied higher on-peak energy charges. Critical peak events are called on a day-ahead basis and can be called between noon and 6:00 p.m., Monday through Friday during the summer months.

Currently, PG&E manages its CPP program in two identified zones, one along the coast where the climate is mild and the other comprising the rest of PG&E's territory, where temperatures tend to be substantially warmer in

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[57] "Identify opportunities and support programs to reduce electricity demand related to the water supply system during peak hours and opportunities to reduce the energy needed to operate water conveyance and treatment systems." (Energy Action Plan II at 5.)

summer months. PG&E states the use of these zones has created confusion for its CPP customers, who may not know when they have been asked to reduce load. PG&E proposes to manage the program on a system wide basis, without breaking down its territory into zones. It believes it may be able to add 7 MW to the program as a result.

PG&E also proposes to modify the CPP program to provide customer notification at noon the day before an event rather than at 3:00 p.m. in order to provide customers additional time to plan for load reductions. PG&E does not anticipate significantly more participation because of this change but notes that it will increase customer satisfaction.

DRA does not object to these proposed program changes but believes the program would be more attractive if it employed "soft triggers" so that CPP events will only be called when load is really needed, rather than according to inflexible guidelines. SCE's program has flexible triggers, and SDG&E has proposed such flexibility in this proceeding.[58]

We will authorize the changes to the CPP program PG&E recommends, but decline to adopt soft triggers since changing the triggers could impact overall program design.

2. Small Customer Aggregation Pilot Program (SCAPP)

The SCAPP provides funding to San Francisco (SF) Power to sign up small and medium sized commercial customers located in Alameda,

58 DRA Opening Comments at 17.

San Francisco, and San Mateo Counties in the CPA-DRP program.[59] D.06-03-024 authorized funding SF Power's efforts for 2006 at a level of $250,000 and would award SF Power an additional $250,000 for 2007 if it signs up 1 MW by the end of 2006. PG&E would extend SF Power's 1 MW deadline until June 1, 2007, so that SF Power can continue its efforts past the end of the year even if it has not signed up 1 MW.[60] SF Power says it has made good progress toward meeting its 2006 goals. Therefore, it requests additional funding—an additional $150,000 in 2007 once a second MW is signed up and $400,000 more in 2008 once 3 MW are signed up. SF Power's goal is to sign up 5 MW by May 2008. SF Power wants to expand its target area to include Contra Costa and Santa Clara counties. It also recommends pursuing 5 MW of permanent load shifting by June 2007 through a program targeted at pallet jack and forklift battery recharging, which was the subject of a CEC-funded study, at a cost of $125,000. Finally, SF Power proposes to permit the aggregation of submeters.[61]

PG&E supports SF Power's recommendations to expand its program provided that additional funding is contingent on meeting performance goals, and expanding the program into additional counties. The utility is not opposed to the permanent load shifting proposal. PG&E is, however, opposed to

[59] On October 19, 2006 the Commission adopted Resolution E-4020, authorizing the Capacity Bidding Program as a successor program to CPA-DRP starting May 2007.

[60] PG&E Opening Comments at 22.

[61] SF Power Opening Comments.

aggregating submeters, arguing that SF Power has overlooked costs required to upgrade electric panels.[62]

The costs of the SCAPP program are for marketing only and are therefore in addition to the incentives and some of the overhead costs incurred by PG&E for the CPA-DRP (or CBP starting May 2007). SF Power's proposal to extend the program to achieve 5 MW in demand response from a difficult to reach customer segment, and to tie program extension to megawatt goals is reasonable. We, therefore, adopt SF Power's proposed expansion. We will also permit SF Power to extend its program into the two additional counties listed above and move forward with the 5 MW permanent load shifting program that it proposes. We deny SF Power's request to aggregate submeters since we do not have sufficient information to fully evaluate costs and benefits.

3. Business Energy Coalition (BEC)

The BEC is a project in San Francisco designed to subscribe hard-to-reach customers into demand response programs. The program is currently targeting 15 MW in 2007 and 25 MW in 2008.

PG&E requests authority to expand the BEC program to motivate 50 MW of subscribed customer load by June 1, 2007. The expansion would include accelerating the 25 MW targeted for 2008 and adding an additional 25 MW. PG&E states it would provide details of this proposal, and a proposal to extend the program for seven years, in a subsequent request once PG&E signs an agreement with BEC. In PG&E's Opening Comments on the Proposed Decision,

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[62] PG&E Reply Comments at 15-16.

the utility clarifies that the expansion of the program to 50 MW in 2007 can be achieved within the existing budget.[63]

Because the BEC program targets hard-to-reach customers and was successful during July 2006, we authorize PG&E's proposal to expand the program in 2007. PG&E does not provide any details of its seven-year extension. Therefore, we decline to authorize the extension at this time and direct PG&E to file an application for approval of its expansion proposal once a new agreement has been signed.

4. Back-Up Generators (BUGs)

PG&E proposes to spend about $15 million in 2007 and $15 million in 2008 to retrofit existing customer-owned diesel back-up generators to primarily run on natural gas. Diesel would still be used as a pilot fuel. The units would be available during Stage 2 alerts. PG&E would pay a customer up to $225.00 per kW in return for a commitment to upgrade the generator and operate on notice from PG&E. BUG owners would also be eligible for capacity payments and be subject to penalties for non-performance. PG&E believes the program would add up to 50 MW of load reduction potential in 2007 and an additional 50 MW in 2008. It states the generators would not be deployed unless they could operate in compliance with air quality requirements.

PG&E's proposal differs from a prior proposal rejected by the Commission in D.05-01-056 in which the utility proposed to add emissions control technologies to diesel engines. Here natural gas would be the primary fuel.

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[63] PG&E Opening Comments on Proposed Decision at 5.

ECI, EnerNOC, and SVLG support the proposal.[64] ECI comments that the health impacts of running generators for a few critical hours are probably small compared to the health and safety impacts of rolling blackouts. EnerNOC asserts that because BUGs are "behind the meter", they reduce load on the grid and should be considered demand response.[65] Aglet also supports it but does not enunciate the reasons for its support. TURN opposes the program on the basis that it is a supply resource, not a demand response resource, and cannot be reasonably evaluated here.[66] SCE is opposed to launching a BUG program for similar reasons.[67]

Our objective in funding demand response programs is to reduce system demand, not to substitute system electricity with electricity generated by off-grid natural gas facilities. We previously found in D.05-01-056 that back-up generation is not a true demand response resource. As TURN states, counting a BUG program as demand response would "turn the Commission's preferred resource loading order on its head."[68] We, therefore, deny PG&E's request to initiate a BUG program.

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[64] ECI Opening Comments at 4, EnerNOC Opening Comments at 16-18, and SVLG Opening Comments.

[65] EnerNOC Reply Comments at 7.

[66] TURN Opening Comments at 15.

[67] SCE Reply Comments at 8.

[68] TURN Opening Comments at 15.

5. Statewide Pricing Pilot (SPP)

PG&E requests $500,000 to extend the E3/SPP rate through June 2007 so that SPP customers can be smoothly transitioned to the residential CPP rate in Spring 2007. Maintaining continuity for SPP participants is important, so we approve PG&E's request.

6. Budget Impact and Cost Accounting

The program enhancements and expansions we approve here can be funded by reallocating existing funds. We find it reasonable that PG&E does not seek additional funding for demand response efforts. We authorize necessary fund shifting, but do not need to authorize additional expenditures at this time.

PG&E tracks its actual expenses against the authorized revenue requirement in the Demand Response Expense Balancing Account (DREBA). The DREBA is a one-way balancing account that prohibits the utility from being compensated for spending more than a pre-approved budget. PG&E intends to update the demand response revenue requirement as appropriate when the utility files additional plans for expanded and new demand response programs, and record the associated expenses in the DREBA.

We encourage PG&E to look for opportunities to expand its demand response programs and create new programs. To the extent additional funding is needed to expand PG&E's efforts, the utility should seek approval from the Commission in advance. PG&E's intended accounting treatment is appropriate provided that the utility obtains Commission approval prior to recording expenses in the DREBA.

Finally, this order does not eliminate the cap on fund-shifting, as PG&E proposes. The cap was adopted in D.06-03-024 as part of the settlement presented in these proceedings. That cap provides adequate flexibility for PG&E

to move program funds according to need while providing some protection for ratepayers against overspending on programs that might not be cost-effective. If PG&E wishes to reallocate additional funds to a program, it may seek such authority by advice letter, consistent with D.06-03-024, and should make a showing of the cost-effectiveness of such a reallocation.

C. SDG&E Proposals and Budget

1. Commercial and Industrial (C&I) Peak Day Credit Program

SDG&E sought and received a variety of changes to its C&I Peak Day Credit Program by way of advice letter filed in July 2006. Those changes were authorized for 2006 only. SDG&E here seeks to extend most of the changes through 2008. Those program elements include allowing for incentive payments for load reductions between 10% and 20% and the softening of triggers so that SDG&E has the discretion to call an event. SDG&E believes these two elements together will improve management of the program and provide a more attractive product to customers. SDG&E does not propose eliminating the maximum number of events as was done in Resolution E-4011.

DRA and TURN object to SDG&E's proposal to extend this program into 2007, observing that the program is not cost effective and provides "virtually no value to ratepayers" because it is not dispatchable and does not result in any measurable load reductions.[69]

We believe that this program could contribute to reliability during peak periods. We acknowledge a need to evaluate this program in more depth

[69] DRA Opening Comments at 21-22 and TURN Opening Comments at 14-15.

with a cost-effectiveness model but in light of our goal to augment demand response for 2007, we approve SDG&E's proposal to extend the C&I peak day credit program through 2008.

2. Residential Smart Thermostat Program

SDG&E proposes to extend its Residential Smart Thermostat Program through 2007 with no changes. This AC Cycling type program would require about $385,000 in reallocation of budget funds. Aglet questions the program's cost-effectiveness[70] Because it provided substantial "day-of" load reductions in 2006, we find the continuation of this program into 2007 to be reasonable.

3. CPP

SDG&E proposes to modify its CPP program by softening the triggers for calling an event and increasing the maximum number of events to 15. For reasons discussed previously, these modifications appear reasonable and designed to improve customer participation, and we adopt them.

4. In-Home Display Program

SDG&E proposes to implement a new program that will offer residential customers the installation of an in-home display device that will provide information to customers on their energy usage and potential cost by the hour, month and month-to-date. A participating customer will be provided educational material and will be asked to reduce his or her energy usage during identified peak periods. The program will be used to understand how customers modify their behavior in response to real-time information. The program will be

[70] Aglet Opening Comments at 7.

offered to 300 customers in 2007 at a cost of about $430 thousand, including a significant measurement and evaluation component.

The testing of real-time in-home displays will provide valuable research about how residential customers respond to real-time information about their energy usage. The findings from this program could be used to enhance other demand response efforts targeted at the residential sector.

5. Program Budgets and Accounting

The program enhancements and expansions we approve here can be funded by reallocating existing funds. We find it reasonable that SDG&E does not seek additional funding for demand response efforts. We authorize necessary fund shifting, but do not need to authorize additional expenditures at this time.

Like PG&E, SDG&E proposes to eliminate limitations on shifting funds between programs, which D.06-03-024 set at 50% of program funds. It would seek Commission approval of other program changes, consistent with D.06-03-024. We are not prepared to permit SDG&E authorization to use program funds at its discretion, largely because we have no adopted cost-effectiveness test by which the Commission or the utility could judge such substantial deviations from the adopted program budget. The existing limitation provides adequate discretion for SDG&E to allocate funds between programs and according to program participation. We do authorize the fund shifting SDG&E proposes here. If SDG&E seeks authority beyond what is adopted here and what is contemplated by D.06-03-024, it should file an advice letter.

D. SCE Proposals and Budget

The program enhancements and expansions we approve for SCE discussed above can be funded by reallocating existing funds. We find it reasonable that SCE does not seek additional funding for demand response efforts. We authorize necessary fund shifting, but do not need to authorize additional expenditures at this time.

E. TURN's Proposal for Swimming Pool Pumps

TURN proposes that the Commission order the utilities to engage third-party contractors to install direct load control equipment on swimming pool pumps. TURN explains that swimming pool pumps can be deployed during off-peak hours without affecting health, safety or the economy. It proposes use of third parties so that the utilities do not need to develop infrastructure prior to implementing such a program.

PG&E opposed TURN's proposal for a variety of reasons. The utility questions TURN's premise that a significant number of pool pumps operate during peak hours. PG&E points out that almost all pool pumps except for those equipped with solar heating or energy efficiency filters are already equipped with timers and many probably do not operate during peak hours. [71]

TURN's idea is interesting but we believe that the magnitude of the potential peak load reduction is unclear at the point. We decline to adopt TURN's proposal, but encourage the utilities to consider pool pumps in the context of demand response programs.

VII. Comments on Proposed Decision

The proposed decision of the assigned Commissioner in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code

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[71] PG&E Reply Comments at 14.

and Rule 14.2(a) of the Commission's Rules of Practice and Procedure. Comments were filed on November 20, 2006 by Aglet, Aloha Systems (Aloha), ACWA, California Community College System, CAISO, CLECA/CMTA, DRA, EnerNOC, Ice Energy, PG&E, SDG&E, SVLG, SCE, and TURN. Reply comments were filed on November 27, 2006 by ACWA, DRA, EnerNOC, Ice Energy, PG&E, SDG&E, SCE, and TURN.

In response to the comments, we have made several clarifications, corrections and changes to the proposed decision.

SCE argues again that aggregators should not participate in BIP. SCE explains that the utility has designed BIP to be integrated with a particular enabling technology and communications network. The technology gives SCE's Grid Control Center (GCC) "near-real time visibility" of load reductions. Aggregated load cannot be connected to the network in the same way, the GCC may, therefore, discount the contribution of such load. SCE points to the day-of CBP as a more appropriate program for aggregation.[72]

DRA recommends requiring tests to ensure that aggregator participation will not hinder the existing BIP program.[73]

Demand aggregators can attract customers that would not otherwise participate in BIP. The load from aggregators will be additive to SCE's existing BIP participation and will not force SCE to change its relationship with its existing BIP customers. Therefore, we do not find SCE's arguments to be persuasive. We also do not see a need to require tests since SCE's existing

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72 SCE Opening Comments on Proposed Decision at 8-9.

73 DRA Opening Comment on Proposed Decision at 13.

program will be unaffected. SCE should work collaboratively with aggregators so that the aggregators can provide the level of visibility, on an aggregated basis, that the utility needs.

In relation to BIP, CLECA/CMTA note that a customer has a window from November 1 to December 1 to inform its utility of any increase or decrease in its firm service level. CLECA/CMTA request an extension of the window so that a customer has 30 days from the date of this decision to consider program changes adopted in this decision.[74] We have modified the decision to authorize an extension.

PG&E explains that the proposed decision's discussion of its AC Cycling proposal in not accurate. PG&E clarifies that it initially requested a $7.5 million budget to install 5,000 switches in 2007 and fund ten years of costs. Alternatively, $7.5 million could fund 15,000 switches in 2007 if the future year costs are approved in a separate application. The utility proposes to establish the final budget through the resolution approving the advice letter.[75]

We support PG&E's proposal to move forward with an AC Cycling program. However, we are concerned that authorizing $7.5 million for an estimated 5 MW may be too expensive relative to other program modifications PG&E has proposed. The Commission needs more information to approve a specific program. We will approve in concept a 5,000 switch program using the existing demand response budget and subject to advice letter review.

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[74] CLECA/CMTA Opening Comments on Proposed Decision at 4.

[75] PG&E Opening Comments on Proposed Decision at 6.

SCE is confused by the proposed decision's directive to allow TA/TI funds to be used for direct customer expenses. SCE is concerned that the directive will require an additional payment beyond the normal TA or TI incentive[76] We are not creating an additional incentive. Rather we are providing the utilities flexibility to use TA/TI funds for a broad range of expenditures, including direct customer costs. If SCE's TA/TI incentives already go toward all of a customer's actual reasonable costs, then the flexibility granted is merely restating the status quo for SCE.

Aloha raises concerns about utility administration of the TA/TI program.[77] The Demand Response Measurement and Evaluation Committee intends to evaluate the TA/TI program in the future and will consider input such as that provided by Aloha.

Based on comments from PG&E and TURN, we have removed the requirement that PG&E implement soft triggers in its CPP program.

The CAISO encourages the Commission to work with the CAISO and other parties to develop demand response program triggers that are aligned with the needs of the grid. Well-aligned demand response programs can add greater capacity and liquidity to the wholesale market, create greater demand elasticity, and tap into an existing, available resource.[78]

The Commission similarly looks forward to working closely with the CAISO to align and integrate the utilities' demand response programs with the

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[76] SCE Opening Comments on Proposed Decision at 6-7.

[77] Aloha Opening Comments on Proposed Decision.

[78] CAISO Opening Comments on Proposed Decision.

wholesale market and the needs of the grid. We are encouraged that the CAISO is engaged in this area.

In addition to revisions made in response to comments, we have made other minor corrections and clarifications to the proposed decision.

VIII. Assignment of Proceeding

Rachelle B. Chong is the assigned Commissioner and Kim Malcolm is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Utility demand response programs are a key to system management during periods of critical need and potential system instability.
2. Many of the program modifications the utilities propose will require advance marketing, and in some cases implementation, in order to have commitments of energy and capacity by summer 2007.
3. The Working Group 2 Measurement and Evaluation subcommittee was authorized to provide oversight of demand response evaluation in D.06-03-024.
4. Third-party contractors may be able to increase participation in demand response programs.
5. PG&E's proposal to increase BIP Option A incentives could attract customers and ease the transition from the Non-Firm program to BIP.
6. No customers have signed up for PG&E's BIP Option B.
7. PG&E's proposed replacement for BIP Option B could be attractive to additional customers.
8. Reopening PG&E's Non-Firm program could confuse customers since the program could be ended as soon as January 1, 2008.
9. Lowering SDG&E's BIP penalties could increase participation.
10. BIP and CBP could appeal to different customers.

11. Allowing aggregators to participate in SCE's BIP could increase demand response.

12. "Soft triggers" for calling demand response events may permit the utilities to manage demand response programs more effectively and in ways that are more attractive to customers than hard and fast event criteria.

13. Replacing the DBP's market-based incentive with a flat incentive and allowing standing bids could simplify the program and increase customer participation.

14. PG&E's proposal for a "no-bid" option as part of its DBP program may be costly and provide little in the way of additional demand response.

15. AC cycling could contribute to concrete load reduction capability in PG&E's service territory.

16. PG&E did not provide detailed budget information for its proposed 2007 AC Cycling program.

17. SDG&E can increase participation in its offering new cycling options.

18. Other jurisdictions have used RFPs to identify new demand response opportunities.

19. Seeking proposals directly from customers and aggregators could unleash innovative and cost-effective demand response technologies and activities.

20. Larger TA and TI incentives can encourage customer participation in demand response programs.

21. Permanent load shifting can reduce the need for capacity investments, reduce the likelihood of shortages during peak periods and lower system costs overall by reducing the need for peaking units.

22. Permanent load shifting is not currently supported by the utilities' demand response budgets.

23. SCAPP currently provides funding to SF Power to sign up small and medium sized commercial customers located in Alameda, San Francisco, and San Mateo counties.

24. The BEC is a program in San Francisco designed to subscribe hard-to-reach customers into demand response programs.

25. BUGs are a supply resource that does not reduce energy demand.

26. Our objective in funding demand response programs is to reduce system demand, not to substitute system electricity with electricity generated by off-grid natural gas facilities.

27. PG&E's Schedule E3 is scheduled to be decommissioned as of December 31, 2006, and the residential CPP rate will not be available until Spring 2007.

28. SDG&E's C&I Peak Day Credit could contribute to reliability during peak periods.

29. SDG&E's Residential Smart Thermostat program provided "day-of" load reductions in 2006.

30. SDG&E proposes changes to its CPP program that are likely to improve customer participation.

31. The testing of real-time in-home displays will provide valuable research about how residential customers respond to real-time information about their energy usage.

32. The magnitude of the potential peak load reduction from direct load control of pool pumps is unclear.

Conclusions of Law

1. The utilities should pursue both price-responsive and reliability demand response tariffs and programs.

2. The Commission should not change the demand response goals in this proceeding.

3. Agency staff should address the issue of revising the existing demand response goals in a proposed rulemaking.

4. The Working Group 2 Measurement and Evaluation subcommittee should be renamed as the Demand Response Measurement and Evaluation Committee and should continue to provide oversight of demand response evaluation.

5. The Energy Division and CEC should have access to information necessary to oversee demand response program evaluation.

6. The Commission should adopt PG&E's proposal to increase BIP Option A incentives and close the existing BIP Option B.

7. PG&E's new BIP Option B should be approved with an incentive level of $0.60/kWh.

8. Aggregators should be permitted to participate in PG&E's BIP Option A and new BIP Option B.

9. PG&E should not permit new customers to sign-up for the Non-Firm program in 2007.

10. SDG&E should be permitted to decrease BIP penalties, adopt additional triggers, and change Rule 29.

11. BIP should be continued as a statewide program, and SDG&E should not be permitted to close its BIP.

12. Aggregators should be permitted to participate in SCE's BIP.

13. SCE should work collaboratively with aggregators so that aggregators can provide the level of viability that the utility needs.

14. It is reasonable to give customers 30 days from the date this decision to adjust their firm service levels for 2007.

15. Flat incentive payments should be adopted for all three utilities' DBPs.

16. PG&E should not be permitted to add a DBP "no-bid" option.

17. SCE and SDG&E should be authorized to add a DBP standing bid option.

18. PG&E, SCE, and SDG&E should be directed to create a day-of DBP program.

19. PG&E's proposal to expand its AC Cycling program for 2007 using the existing demand response budget is reasonable in concept, but the utility should provide a final budget and additional details to the Commission.

20. SDG&E's proposals to add cycling options to its Summer Saver program are reasonable.

21. PG&E and SCE should be directed to run RFPs or seek bilateral contracts for new demand response proposals.

22. PG&E, SCE, and SDG&E should be authorized to increase TA/TI incentives.

23. PG&E, SDG&E and SCE should be ordered to file a detailed plan for the implementation of Auto DR. The plans should include proposals for working with the DRRC, providing quality control and oversight of their 3rd party implementation contractors, how TA/TI funds will be used, and a detailed budget that identifies administrative, evaluation and incentive costs.

24. Allocating demand response funds to permanent load shifting programs to reduce summer 2007 peak load is reasonable.

25. The IOUs should seek permanent load shifting proposals through an RFP process and bilateral arrangements.

26. PG&E's proposed changes to its CPP program are reasonable and should be approved.

27. The changes to the SCAPP program proposed by SF Power, with the exception of the submetering proposal are reasonable and should be approved.

28. PG&E should be authorized to expand the BEC program to achieve a total of 50 MW of load reduction by June 1, 2007.

29. The Commission should consider an application to extend the BEC program for seven-years.

30. PG&E should not be permitted to implement its proposed BUGs program.

31. PG&E should be authorized to extend the Schedule E3 rate until June 2007 so that customers may be transitioned to the residential CPP rate.

32. PG&E's cap on fund shifting should be retained.

33. SDG&E should be permitted to extend its C&I Peak Day Credit Program through 2008.

34. SDG&E should be authorized to extend its Residential Smart Thermostat Program through 2007.

35. SDG&E's proposed modifications to its CPP program are reasonable and should be approved.

36. SDG&E should be authorized to initiate a In-Home Display Pilot Program.

37. SDG&E should not be authorized to change its accounting or ratemaking for demand response programs except to the extent explicitly provided for herein. SDG&E's cap on fund shifting should be retained.

38. TURN proposal to require direct load controls for pool pumps should not be approved at this time.

IT IS ORDERED that:

1. Pacific Gas and Electric Company, (PG&E), San Diego Gas & Electric Company, (SDG&E), and Southern California Edison Company (SCE) shall provide all data and background information used in monitoring and evaluation

projects to the Energy Division and the California Energy Commission (CEC), subject to appropriate confidentiality protections. In addition, we direct the investor-owned utilities (IOUs) to provide appropriate subsets of these data to vendors and academic researchers selected by the Commission or the CEC, such as the Demand Response Research Center, to conduct additional monitoring and evaluation projects, under appropriate confidentiality protections.

2. PG&E, SCE, and SDG&E shall, within 15 days of the effective date of this order, file tariffs in compliance with this order.

3. PG&E and SDG&E are required to give BIP customers 30 days from the date this decision is adopted to adjust their firm service levels for 2007.

4. PG&E shall file an advice letter within 20 days to implement an Air Conditioning (AC) Cycling program for 2007 consistent with this decision. PG&E shall provide detailed budget information including the costs of installing the switches, incentives, and any other costs.

5. PG&E and SCE shall pursue Requests for Proposals (RFP) and bilateral arrangements for additional demand response resources and file an application with the Commission requesting approval for specific contracts by February 28, 2007.

6. PG&E, SDG&E and SCE shall within 30 days of this order submit to the Commission's Energy Division plans for implementing Auto DR, consistent with this order. This plan shall be for one year.

7. PG&E, SDG&E and SCE shall, by October 31, 2007, file proposals for continuation or modification of their AutoDR programs.

8. PG&E and SCE shall pursue a RFPs and bilateral arrangements for permanent load shifting for the summer of 2007. Each IOU is directed to file an advice letter with their selected proposals by February 28, 2007. PG&E, SDG&E,

and SCE are authorized to shift up to $10 million, $4 million, and $10 million respectively of their existing demand response budgets.

9. PG&E shall file an application for approval of a seven-year extension of the Business Energy Coalition program.

This order is effective today.

Dated November 30, 2006, at San Francisco, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
Commissioners