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Decision 09-08-027 August 20, 2009

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Demand Response Programs, Goals and Budgets for 2009-2011.	Application 08-06-001 (Filed June 2, 2008)
And Related Matters.	Application 08-06-002 Application 08-06-003

DECISION ADOPTING DEMAND RESPONSE ACTIVITIES AND BUDGETS FOR 2009 THROUGH 2011

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DECISION ADOPTING DEMAND RESPONSE ACTIVITIES AND BUDGETS FOR 2009 THROUGH 2011

1. Summary

This decision adopts demand response activities and budgets for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the utilities) to conduct demand response programs and pilots for the remainder of 2009 through December 31, 2011. This decision approves utility demand response programs, some with modifications from previous years, and authorizes several demand response pilot programs to test new demand response-related technologies and integration of demand response with Advanced Metering Infrastructure systems. This decision also provides funding for evaluation, measurement, and verification of demand response activities, and continues existing cost recovery mechanisms for demand response–related funding. In addition, this decision adopts a new methodology for calculating settlement baselines for certain demand response activities, and adopts rules on concurrent customer participation in more than one demand response program.

The total adopted budget for all three utilities' demand response programs for 2009-2011 is $349,509,463. This decision adopts a budget of $188,806,349 for SCE, of which approximately $38.8 million will support the aggregator contracts adopted in this decision. The total adopted budget for PG&E is $109,060,072, and the total adopted budget for SDG&E is $51,643,042. With the adoption of this decision, this proceeding is closed.

2. Procedural Background

In Decision (D.) 06-03-024, the California Public Utilities Commission (Commission) approved Demand Response activities and budgets for SCE, SDG&E, and PG&E for 2006 through 2008, and required these utilities to file utility-specific demand response program and budget applications for the 2009 to 2011 time period by June 1, 2008. On February 27, 2008, a Guidance Ruling provided specific instructions to the utilities on the expected scope and contents of those applications. On April 11, 2008, Commissioner Rachelle B. Chong issued joint guidance with Commissioner Dian M. Grueneich on how joint energy efficiency and demand response programs should be addressed in the demand response and energy efficiency program and budget applications.[1] On June 2, 2008, the utilities filed the applications captioned above, Application (A.) 08-06-001 (by SCE), A.08-06-002 (by SDG&E), and A.08-06-003 (by PG&E).

On July 2, 2008, the Administrative Law Judge (ALJ) assigned to these applications issued a ruling that consolidated the applications and confirmed a due date of July 9, 2008, for protests or responses. Many parties filed protests or responses to these applications,[2] and all three utilities filed replies on July 21, 2008. In addition, Commission staff performed a review of the applications to determine whether they complied with the requirements of the earlier guidance rulings. Energy Division staff also met with each utility separately between June 27 and July 1, 2008, to describe general deficiencies in each application. The

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[1] Joint Assigned Commissioner Ruling Providing Guidance on Integrated Demand Side Management, April 18, 2008.

[2] The following parties filed protests or responses to applications A.08-06-001 et al.: the Alliance for Retail Energy Markets (AReM), the California Independent System Operator (CAISO), California Large Energy Consumers Association (CLECA), Chapeau Inc., dba Blue Point Energy (BluePoint), ConsumerPowerline, Inc., the Division of Ratepayer Advocates (DRA), Ice Energy, Inc., Kinder Morgan Energy Partners LP, The Utility Reform Network (TURN), Transphase Inc. (Transphase), and jointly by Comverge Inc., EnerNOC Inc. (EnerNOC), and EnergyConnect, Inc. (EnergyConnect).

utilities were informed at that time that the ALJ would issue a ruling directing the deficiencies to be corrected.

On August 6, 2008, the assigned ALJ issued a ruling requiring the utilities to file amended applications by September 8, 2008, to correct deficiencies in the originally filed applications. That ruling also required protests to those amended applications to be filed by September 18, 2008, and scheduled a prehearing conference (PHC) for September 24, 2008. A later ALJ ruling modified these deadlines, with the amended applications due September 19, 2008, protests and responses due on September 29, 2008, and the PHC on October 1, 2008.

On September 5, 2008, the utilities filed a motion for funding and authorization to operate demand response programs and pilots in 2009 (the Bridge Funding Motion) requesting that the Commission issue a decision in November 2008 approving, among other things, the continuation of existing demand response programs and the implementation of certain demand response pilots in early 2009. At the PHC on October 1, 2008, parties discussed both the Bridge Funding Motion and the scope and schedule for the review of the full applications. The Scoping Memo in this proceeding, issued on November 10, 2008, defined the scope and schedule for resolving both the Bridge Funding Motion and the main portion of the proceeding, among other issues. On December 18, 2008, the Commission issued D.08-12-038, approving the Bridge Funding Motion with modifications; this decision authorized the utilities to continue certain demand response programs through 2009 or until a decision is issued on the programs and budgets for 2009-2011 in the main portion of this proceeding.

Hearings were held January 6-9 and January 20, 2009. Parties filed opening briefs on most issues on January 28, 2009,[3] with opening briefs on San Francisco Community Power and Transphase issues filed on February 4, 2009.[4] Parties filed reply briefs on February 11, 2009.[5] The assigned ALJ requested additional information on cost effectiveness calculations to be filed February 23, 2009, with party comments March 2, 2009. All three applicants filed additional information, and CLECA filed responses on March 2, 2009. With the permission of the assigned ALJ, all three applications filed replies to the CLECA responses on March 5, 2009.

SCE, DRA, EnerNOC, and Alternative Energy Resources, Inc. (AER) filed a settlement agreement on February 23, 2009, proposing the adoption of certain demand response contracts between SCE and third-party aggregators. The record was closed and the proceeding was submitted on March 5, 2009. Subsequently, PG&E filed two motions on March 25, 2009. The first motion requested adoption of a settlement agreement between PG&E and SF Power resolving issues related to the Small Commercial Aggregation Program and asking for a waiver of the time limit for filing a settlement contained in Rule 12.1(a),[6] and the second requested that the time for responding to the first

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[3] The following parties filed opening briefs on January 28, 2009: BluePoint, the California Demand Response Coalition (CDRC), TURN, DRA, CPower, CAISO, Chapeau, CLECA, PG&E, SCE, and SDG&E.

[4] The following parties filed opening briefs on February 4, 2009: SF Power, Transphase, PG&E (on SF Power issues), and PG&E, SCE, SDG&E (jointly, on Transphase issues).

[5] The following parties filed reply briefs on February 11, 2009: BluePoint, San Francisco Community Power (SF Power), CAISO, CPower, Energy Curtailment Specialists, Transphase, Chapeau, SDG&E, DRA, TURN, CDRC, PG&E, CLECA, and SCE.

[6] All references to Rules are to the Commission's Rules of Practice and Procedure.

motion be shortened from 30 days to seven days. ALJ Hecht granted the request to waive the time limit for filing a settlement, and shortened the comment periods on the settlement agreement. No comments were filed on this settlement agreement.

Also on March 25, 2009, Energy Curtailment Specialists (ECS) filed timely comments on the settlement agreement filed on February 23, 2009, related to the SCE demand response contracts. The comments filed by ECS opposed the adoption of the settlement agreement unless certain terms agreed upon in the settlement agreement that are beneficial to the aggregators are adopted for the proposed SCE/ECS contract, also. Both SCE and DRA filed reply comments objecting to the ECS request that the Commission either reject the settlement on aggregator contracts or apply certain terms to the ECS contract, also. SCE and ECS filed a motion asking to withdraw the ECS contract from consideration in this proceeding on April 17, 2009. The record was resubmitted on April 17, 2009.

3. Late-Filed Exhibits

Three exhibits were received from parties after hearings. At hearings, TURN suggested entering a filing from the demand response Rulemaking (R.) 07-01-041 into the record as an exhibit to provide context for understanding the cost effectiveness analyses contained in the applications. In the Guidance Ruling dated February 27, 2009, the applicants were directed to use the cost effectiveness framework filed by parties in R.07-01-041 in November of 2007 as the basis of their cost effectiveness calculations on existing and proposed programs.[7] No parties objected to the inclusion of this "Consensus Framework"

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[7] Joint Comments Of California Large Energy Consumers Association, Comverge, Inc., Division Of Ratepayer Advocates, Energyconnect, Inc., Enernoc, Inc., Ice Energy, Inc.,

Footnote continued on next page

as an exhibit in this proceeding to be served after the end of hearings, and the exhibit was identified as Exhibit 417. TURN served the exhibit on parties to this proceeding, and no parties have subsequently objected to including this exhibit in the record. Exhibit 417 is hereby received.

During a supplemental day of hearings held on San Francisco Community Power and Transphase issues on January 20, 2009, ALJ Hecht requested PG&E and SF Power prepare and enter into the record their own analyses of the demand response provided during 2008 by customers enrolled in PG&E's Capacity Bidding Program through SF Power. No parties at hearings objected to admitting these analyses as exhibits after the end of hearings, and the exhibits were numbered 217 (for the PG&E analysis) and 802 (for the SF Power analysis). No parties have subsequently objected to including these exhibits in the record. Exhibits 217 and 802 are hereby received.

The record is composed of all documents that were filed and served on parties. It also includes all testimony and exhibits received at hearing, and the three exhibits described above that were identified at the hearings and served on all parties in response to direction at the hearing. Also, the ALJ sealed as confidential various exhibits and filings. We affirm all assigned Commissioner and ALJ rulings in this proceeding. All motions not previously ruled upon or addressed in this decision are denied.

Pacific Gas And Electric Company (U 39-M), San Diego Gas & Electric Company (U 902-E), Southern California Edison Company (U 338-E) And The Utility Reform Network Recommending A Demand Response Cost Effectiveness Evaluation Framework," (sometimes known as the Consensus Framework) filed November 19, 2007, in R.07-01-041.

4. Alliance for Retail Energy Market/Electric Service Provider Issues

In its protest and at the PHC, AReM raised several technical issues related to the ability of Electric Service Providers (ESPs) and their customers to participate in Commission-approved Demand Response activities run by the utilities or by aggregators under contract with the utilities. The scoping memo in this proceeding directed the applicants, AReM, and other parties intending to address these issues in testimony, cross-examination at hearings (if necessary), or in briefs to participate in a settlement conference to address the need for improved coordination among ESPs and utilities, and to file a joint status report on aggregator issues by December 22, 2008. A settlement conference to discuss ESP issues was noticed to all parties in A.08-06-001 et al. and held on December 10, 2008. According to the joint status report filed on December 22, 2008, in compliance with the scoping memo, AReM, all three utilities, DRA, the Energy Users Forum, and EnerNOC participated in the settlement conference. As a result of these efforts, AReM and the utilities "informally resolve[d] all the issues raised by AReM in A.08-06-001 *et al.*"[8]

No parties to this proceeding objected to this voluntary agreement, and AReM and the utilities withdrew their previously served testimony relating to these issues, which was not entered into the record. We agree that no further issues related to AReM's initial protest must be resolved in this proceeding, and so ESP and Direct Access issues are not further addressed in this decision.

[8] Joint Status Report on Energy Service Provider Issues, filed December 22, 2008, p. 3.

5. Integrated Demand-Side Management Proposals Deferred to A.08-07-021

As required in the April 11, 2008, Joint Assigned Commissioners' Ruling Providing Guidance on Integrated Demand-Side Management,[9] both the demand response applications filed on June 2, 2008, and the energy efficiency applications filed on July 21, 2008, included proposals for certain pilot programs, marketing, education, and outreach activities, and other activities intended to promote coordination among demand response and energy efficiency activities. These proposals were expected to be included within the scope of both the demand response application proceedings (A.08-06-001 et al.) and the energy efficiency application proceedings (A.08-07-021 et al.).

Consistent with this expectation, the Scoping Memo in this proceeding stated that the IDSM "activities [in these demand response applications] mirror proposals made in the Energy Efficiency Applications proceeding. These proposals are within the scope of both proceedings, and will be reviewed in both."[10]

On March 2, 2009, SCE, SDG&E, SoCalGas, and PG&E filed amended applications in A.08-07-021 et al. that included revised proposals on IDSM.

Due to the advanced stage of review on the non-IDSM issues within this proceeding at the time that revised IDSM proposals were filed, the assigned

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[9] For the purposes of this decision, Integrated Demand Side Management (IDSM) consists of proposals included in the utilities' applications relating to coordination among energy efficiency, demand response, and other demand-side management activities that are responsive to the April 18, 2008 Joint Assigned Commissioner's Ruling.

[10] A.08-06-001 et al., Assigned Commissioner's and Administrative Law Judge's Scoping Memo and Ruling, November 10, 2008, p. 9.

Commissioner and ALJ issued a ruling on March 26, 2009 modifying the scope of this proceeding to defer review of IDSM proposals to the energy efficiency applications proceeding, A.08-07-021 et al.[11] That ruling advised parties interested in participating in the review of IDSM activities for 2009-2011 to take part in the energy efficiency portfolio applications, A.08-07-021 et al.

To be consistent with the March 26, 2009, ruling, the April 2008 Guidance Ruling, and D.07-10-032, the Commission will also defer review of the utilities' 2010 and 2011 marketing, education, and outreach proposals in these applications to the energy efficiency applications proceeding. To determine if the utilities' proposals are following this direction, it is appropriate to evaluate the proposals in the context of the energy efficiency marketing proposals. To ensure that the utilities are able to continue these activities until a decision is issued in the energy efficiency proceeding, we will adopt budgets for marketing, education, and outreach in this decision.

6. Summary of the Applications

The amended demand response applications filed on September 19, 2008, contained descriptions of demand response activities and programs, as well as historical information about programs operating during the 2006-2008 period. Activities described in the applications include proposals to continue (with and without modifications) several programs that existed in previous years, as well as proposals for new programs and pilots. The following sections briefly outline each company's amended application.

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[11] Assigned Commissioner and Administrative Law Judge's Ruling Amending Scoping Memo and Deferring Consideration of Integrated Demand-Side Management Issues to Application 08-07-021 et al., p. 3.

6.1. SCE – A.08-06-001

The total budget for SCE's requested demand response activities is $234.4 million. Specific requests include the continuation of several existing demand response programs (some with modifications), approval of contracts with third-party demand response aggregators, continuation of existing fund-shifting rules during the 2009-2011 period, and authority for SCE to make certain program modifications via advice letters. SCE also requests approval of its proposed ratemaking treatment; its proposed evaluation, measurement, and verification activities; as well as marketing, education, and outreach activities.

6.2. SDG&E - A.08-06-002

SDG&E proposes to simplify its demand response programs in order to increase customer participation. SDG&E's request also includes funding for evaluation and measurement activities, as well as outreach, education, and marketing. SDG&E requests approval for $48.535 million in new funds to augment $12.080 million in previously-authorized funding.[12]

6.3. PG&E - A.08-06-003

PG&E recommends the continuation of several existing demand response activities in their current form, and PG&E requests the authority to continue its existing PeakChoice and Capacity Bidding Programs with modifications. PG&E also requests changes its settlement baseline calculations for most programs, and asks to expand its Business Energy Coalition Program. In addition, PG&E seeks

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[12] Unlike SCE and PG&E, SDG&E collects its demand response funding in arrears, after it is spent. For this reason, SDG&E has not yet collected funds approved for 2008-2009 but not yet spent, and it would need to collect not only any newly approved funding authorized in this decision but also the previously authorized funds, for a total budget of $60.615 million.

authority to hold a competitive solicitation for new aggregator contracts. PG&E also seeks approval for several new pilot programs and studies; its evaluation, measurement, and verification activities; and its proposed marketing, education, and outreach activities. PG&E requests a total budget for all 2009-2011 demand response activities of $147,223,000. PG&E also requests permission to make changes to the adopted programs during the 2009-2011 period via advice letters, and to shift funds between approved programs within the same budget category.

7. Factors Considered in Review of Proposals

One main criterion for determining whether or not to adopt a particular demand response activity is whether or not that program is cost effective. However, because demand response programs are relatively new compared to other forms of demand-side management such as energy efficiency, there is still a great deal of uncertainty about the best way to measure the cost effectiveness of these programs. The Commission has not yet adopted a standard cost effectiveness methodology, in part because many of the costs and benefits of demand response programs are intrinsically difficult to measure and compare. In part for these reasons, cost effectiveness of an individual program will be one important factor considered in evaluating proposed activities, but it will not be the only criterion relevant to this determination. The following list includes factors that have been considered in evaluating the programs:

1. **Cost effectiveness:** The cost effectiveness analysis contained in these applications is based on a Consensus Framework proposed by most of the parties in R.07-01-041. This framework is not as broad as the subsequent protocols proposed by Commission staff, which required a sensitivity analysis of many inputs rather than a single benefit/cost ratio for each program and test. However, it does provide a useful estimate for examining the cost effectiveness of programs. For a more detailed discussion of

the usefulness and limitations of the Consensus Framework cost effectiveness estimates used in these applications, see Section 7.1 below.

2. **Track record of performance for continuation of existing programs:** This includes, but may not be limited to, actual load drop (especially compared to enrolled load and estimated load drop), target groups and types of participants, actual cost, how often it was called, actual load drop rate, actual load pick-up rate, and other factors as appropriate.

3. **Projected future performance:** Expected performance in the future including, but is not necessarily limited to, estimated participation (customers and enrolled load) and estimated load drop at peak times.

4. **Cost.**

5. **Flexibility or versatility:** Whether a program can be called under a variety of circumstances, or only in very rare or specialized situations. For example, does the program have multiple triggers? Can it be called on a price responsive basis for simple day to day resource dispatch, as well as for contingency matters such as emergencies? Can it be called in non-summer months to respond to generator outages?

6. **Adaptability to changes in the structure of the electricity market:** Ability of a program to adapt to the Market Redesign and Technology Upgrade (MRTU) and the new CAISO markets. For example, is a program likely to be able to supply some of the operational characteristics of Proxy Demand Resource or participating load? What interaction or shared dispatch and control could CAISO have with the program?

7. **Locational value:** Whether the program can be called by location. For example, can the program be activated ("called") by specific location if necessary, particularly in transmission and distribution congestion areas? Does the program help to alleviate

a particular geographic challenge? Does it count towards locational resource adequacy or more specific local needs?

8. **Integration with advanced metering infrastructure, Smart Grid, and emerging technology:** What enabling technologies are required for the program? Would this enabling technology become obsolete or redundant once AMI is installed at the participant customers site? Will the program increase the operational capability of AMI? How might the program contribute to a Smart Grid?

9. **Consistency of offerings throughout the state:** Are equivalent programs available in or appropriate for other parts of the state? Is the program consistent enough across utilities that commercial customers with multiple facilities can participate easily?

10. **Simplicity/Understandability:** Can customers understand how the program operates and what is expected of them?

11. **Customer acceptance and participation:** Are participating customers likely to recognize that the program had been called? Is participation likely to cause customer hardship? Can the customer override an event – if so what does the utility expect will be the rate of customer override?

12. **Environmental benefits:** Does the program have any particular environmental benefits that other programs do not have? Does the program help with firming intermittent renewable energy?

13. **Contribution to existing Commission or state policies and goals:** Is the program consistent with statewide goals or policies? For example, will the program simply shift usage from peak to another time or does the program also reduce overall usage? Is it integrated with other demand-side programs? Does it result in significant greenhouse gas (GHG) reductions?

7.1. Usefulness and Limitations of Cost Effectiveness Analysis

The utilities have provided cost effectiveness estimates, as directed,[13] based on the Consensus Framework. These estimates consist of benefit/cost ratios calculated using four cost effectiveness tests based on the state's Standard Practice Manual[14] for evaluation of energy efficiency programs – the Total Resource Cost (TRC), Ratepayer Impact Measure (RIM), Participant and Program Administrator Cost (PAC) tests. A motion to adopt the Consensus Framework was filed by most parties to R.07-01-041, including CLECA, the party that raised the most concerns about the implementation of that framework in this proceeding.

Though the Commission has not adopted a demand response cost effectiveness protocol, the Consensus Framework represents the most widely supported option available for estimating demand response cost effectiveness. Nevertheless, we recognize that this method is preliminary and not without problems. Several parties have pointed out what they see as deficiencies, inconsistencies or inaccuracies with the utilities' method of estimating cost effectiveness. Claims made by various parties include:

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[13] Guidance Ruling, February 27, 2008, p. 24.

[14] The California Standard Practice Manual identifies the cost and benefit components and cost effectiveness calculation procedures from four major perspectives: Participant, Ratepayer Impact Measure (RIM), Program Administrator Cost (PAC) and Total Resource Cost (TRC). See the Standard Practice Manual at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

- The utilities are calculating the Avoided Cost of Capacity using combustion turbine costs which are too low.[15]
- PG&E's gross margins are too high.[16]
- The utilities used three different discount rates,[17] time horizons and lifecycles to compute the net present value of the benefits and costs.
- The three utilities used different input assumptions to compute avoided costs so that it is difficult to compare the cost effectiveness of the same programs across different utilities.[18]
- The avoided Transmission and Distribution (T&D) cost for PG&E is calculated incorrectly.[19]
- No party has provided a convincing argument for the inclusion of avoided T&D costs.[20]
- The Avoided T&D cost is applied incorrectly.[21]
- PG&E did not provide an appropriate Avoided T&D cost analysis.[22]
- The utilities' assumption that participant benefits are equal to participant costs skews the cost effectiveness results, since participant benefits are actually greater than, not equal to, participant costs for voluntary programs.[23]
- The utility's adjustments to the Avoided Capacity Cost based on LOLE/P calculations are inaccurate and inconsistent.[24]
- The utility's method exaggerates the benefits and does not include all the costs.[25]

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[15] CDRC Opening Brief, pp. 5; 6-8.

[16] CDRC Opening Brief, pp. 5; 9-10.

[17] CLECA March 2, 2009 comments.

[18] DRA Opening Brief, p. 33.

[19] TURN Opening Brief, p. 15.

[20] DRA Opening Brief, p. 18; CAISO Opening Brief, p. 11.

[21] CLECA March 2, 2009 comments.

[22] TURN Opening Brief, p. 15; CLECA, CLECA March 2, 2009 Comments.

[23] CDRC Opening Brief, pp. 6 and 11-13.

[24] CDRC Opening Brief, pp. 6; 13-16.

[25] TURN Opening Brief, pp. 18-25.

- The cost effectiveness of statewide programs should not differ that much across the state.[26]

Some of these criticisms may have merit. We view the utilities' cost effectiveness estimates as, therefore, just that – estimates. SCE notes that "this [demand response] program cycle is the first time the [utilities] have attempted to implement a common framework (the Consensus Framework) for evaluating demand response program cost effectiveness. It is not surprising that the process has revealed quantification differences among the [utilities]."[27] We believe that despite the variability in the utilities' calculations, the cost effectiveness analyses contained in these applications represent an improvement over calculations contained in previous demand response applications. We agree with SCE that the differences are unlikely to materially impact the Commission's ability to determine whether the demand response proposals are reasonable and should be authorized for 2009-2011, and should not stand in the way of our review of the application.

We find that the cost effectiveness analyses included in the applications, while somewhat flawed, are sufficient for our purposes in this proceeding. In the long term, we need an improved cost effectiveness methodology that will be implemented consistently by all three utilities in order to accurately measure, compare, and choose among existing and proposed demand response activities. We expect to adopt an improved cost effectiveness method in Phase 1 of R.07-01-041 to get us closer to this goal of a consistent analysis to be used in

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26 CLECA, p. 2 and Exhibit 601.

27 SCE Reply to CLECA Comments, March 5, 2009, p. 2.

future demand response applications. It is likely that, as more is learned about the evaluation, measurement, and verification of demand response activities (an area that is not currently well understood), even that methodology can be improved over time. To the extent that there are any deficiencies in the cost effectiveness methodology, parties should raise the concerns in the ongoing Phase 1 of R.07-01-041, and not in this proceeding.

Nevertheless, we acknowledge the issues raised by parties and recognize the limitation of the provided cost effectiveness analyses as we review and evaluate the many proposals contained in these applications. We note that, in particular, there is a wide variation of benefit/cost ratios among the three utilities, making it difficult to compare the relative cost effectiveness of programs across utilities. Even similar statewide programs show large variations in cost effectiveness across the state. This could be due to a number of factors; for example, it could be a result of variations in resource mix, utility infrastructure, local construction costs, and other factors (as claimed by PG&E[28]) or could reflect differences in assumptions and details used in calculations under the consensus framework. Without a more consistent methodology, we cannot be certain that these disparities reflect real differences in program performance and the actual cost effectiveness results of the three utilities' programs. For example, PG&E's benefit/cost ratios are mostly between 0.5 and 1, SCE's are all close to 1, and SDG&E's are all above 1. It is possible that these varying results reflect differences in calculation, rather than differences in program performance. Despite these problems, we believe that the utilities' cost effectiveness estimates

[28] PG&E Reply Brief, p. 8.

are accurate enough to be used in this proceeding. In most cases, this decision cites the results of the Total Resource Cost (TRC) test, though the results of the Participant Test, Ratepayer Impact Test, and Program Administrator Cost Test have also been analyzed by parties and Commission staff. This is not meant to imply that the TRC costs are preferred to, or more important than, the results of the other three tests. All four tests have been considered; for simplicity, the discussion in this decision uses the TRC tests to compare programs among utilities. We use the utilities' analysis as provided; however, we do so with the recognition that these benefit/cost ratios are only estimates of Demand Response programs' cost effectiveness.

8. Positions of the Parties

Including the three applicants, 10 parties participated actively in hearings, and several other parties filed briefs. Certain parties, such as BluePoint Energy, Transphase, and SF Community Power limited their participation to relatively narrow areas of interest, while other parties, such as TURN and DRA, conducted reviews of several facets of the applications and made overall recommendations for the handling of the applications. This section contains brief summaries of the positions taken by the main non-applicant parties in this proceeding.

8.1. BluePoint

BluePoint advocated for the Commission to allow certain types of backup generation (BUGs) to receive demand response funds through the Technical Assistance and Technology Incentives program. BluePoint argues that this is appropriate because BUGs are demand-side resources that reside behind the utility electric meter, and can be configured to look like demand response and function as participating load.[29] In addition, BluePoint argues that BUGs can use renewable fuels such as biogas to reduce demand on the grid at peak times. BluePoint also recommends that the Commission allow demand response aggregators to access the energy market through the utility, with the utility acting as scheduling coordinator.[30] BluePoint argues that this will benefit both utilities and aggregators.

8.2. Transphase

Transphase focuses on expanding the availability of permanent load shifting. Transphase proposes that the Commission require the utilities to offer rebates and incentives directly to customers who choose to install thermal energy storage or permanent load shifting. Under the Transphase proposal, utilities would be required to provide a permanent load shifting "standard offer" program that would offer rebates of up to $1,400 per installed kilowatt of permanent load shifting over the 2009-2011 period.

8.3. SF Power

SF Power makes several proposals related to demand response programs in and around the San Francisco area. In particular, SF Power proposes the continuation of its Small Commercial Aggregation Pilot Program (SCAP) adopted and expanded by the Commission in 2007, and the adoption of a municipal pump load demand response pilot.[31] In addition, SF Power requests that the approval of certain PG&E proposals in the San Francisco area be

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[29] BluePoint Opening Brief, p. 3.

[30] BluePoint Opening Brief, p. 5.

[31] SF Power Opening Brief, p. 27.

contingent on crediting the energy saved by those programs towards the power otherwise provided by certain generators that operate primarily at peak times ("peakers") within San Francisco, such as the Potrero Power Plant, in order to hasten the retirement of those generators.[32] SF Power also recommends that the Commission provide incentives to third parties to enroll customers in available demand response programs in lieu of approving PG&E's proposals for marketing, education, and outreach.[33] In addition, SF Power advocates for various changes in PG&E's Capacity Bidding Program[34] and Automated Business Energy Coalition program,[35] the replacement of APX as the provider of data and Web-based services for demand response programs,[36] expansion of access to the technical incentives program, termination of the Peak Student Energy Actions Program,[37] and consolidation of multiple meters at a single facility in appropriate situations.[38]

8.4. CLECA

CLECA advocates for the continuation of the Base Interruptible Program as a separate program rather than as an option under "cafeteria style" programs such as PG&E's Peak Choice program.[39] CLECA argues that the structural

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[32] SF Power Opening Brief, pp. 10-14.

[33] SF Power Opening Brief, February 4, 2009, pp. 2-5.

[34] SF Power Opening Brief, pp. 5-9.

[35] SF Power Opening Brief, p. 10.

[36] SF Power Opening Brief, p. 9.

[37] SF Power Opening Brief, p. 13.

[38] SF Power Opening Brief, pp. 29-31.

[39] CLECA Closing Brief, p. 6.

differences between the Base Interruptible Program and many other programs would cause confusion for customers and reduce the effectiveness of the Base Interruptible Program model if Base Interruptible Program were subsumed in another program. CLECA also argues that customer participation in multiple programs should be allowed as long as customers are not paid more than once for the same load reduction, and advocates for an agreement between SDG&E and CLECA under which SDG&E will track Peak Time Rebate payments to customers also participating in SDG&E's Summer Saver program, in order to allow dual program participation without duplicative payments.[40]

8.5. CDRC

The CDRC, which represents a group of demand response aggregators, argues that the avoided costs used to calculate the benefit to cost ratios are too low, that the avoided costs of transmission and distribution should be included in the cost effectiveness calculations, and that the utilities have underestimated the customer benefits used in the cost effectiveness analysis. CDRC also advocates for timely approval of third-party aggregator contracts, and for changes in the baseline methodologies used by the utilities for settlement purposes. In addition, CDRC encourages the Commission to expand customer participation in demand response activities by allowing customers to participate in more than one demand response program at a time.[41]

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[40] CLECA Closing Brief, pp. 8-9.

[41] CDRC Opening Brief, p. 3 (summary).

8.6. TURN

TURN argues that the cost effectiveness analyses used in the utilities' applications is flawed, and that the administrative costs associated with many of the proposed programs are excessive. In general, TURN argues for reductions to the funding of many of the utilities' proposed programs and pilots, and especially for the reduction of costs related to administration, education, and marketing.

8.7. DRA

DRA contends that in evaluating demand response proposals, "[c]ost-effectiveness should be considered the most important factor that reveals whether further analysis is warranted."[42] DRA argues that, with few exceptions, the other identified criteria are either taken into account in the cost effectiveness analysis or in the utilities' Load Impact analysis, or cannot be meaningfully evaluated until the Commission more clearly defines certain policies and goals for demand response. One exception, according to DRA, is the criterion requiring adaptability to changes in the structure of the electricity market, which DRA includes in its own proposed ranking system for evaluating the proposals made in this proceeding. DRA's ranking proposal incorporates the utilities' cost effectiveness estimates with their Load Impact analysis and the probability that a program can be integrated into the new CAISO markets. DRA ranks programs as follows:

> **Rank 1:** Programs included in this rank will have a Total Resource Cost Benefit/Cost (TRC B/C) ratio greater than 1.0, and likely to provide *ex-post* load impacts close to the utilities' *ex-ante* estimates

[42] DRA Opening Brief, p. 7.

> used in their cost effectiveness calculations, and are either furthest along or have the greatest potential of being integrated with CAISO's MRTU in a cost effective manner.
>
> **Rank 2:** Programs included in this rank will have the potential to have a TRC B/C ratio greater than 1.0 and are likely to provide *ex post* load impacts close to the utilities' *ex-ante* estimates used in their cost effectiveness calculations. These programs could be integrated with CAISO's MRTU, but the current estimates of costs of such integration appear to be excessive.
>
> **Rank 3:** Programs included in this rank will have the potential to have a TRC B/C ratio greater than 1.0 and are likely to provide *ex-post* load impacts close to the utilities' *ex-ante* estimates used in their cost effectiveness calculations, but could not be integrated with CAISO's MRTU because of the specific structure of the programs.
>
> **Rank 4:** Programs included in this rank will have a TRC B/C ratio extremely low, i.e., less than 0.5. Some of these programs also have a very poor record of providing actual load reduction close to their contractual commitments. These programs are generally not self sustaining and do not justify continued ratepayer support.[43]

DRA ranks PG&E's Business Energy Coalition programs as Rank 4, the statewide Base Interruptible Program as Rank 3, and all other programs as Rank 2. DRA recommends:

> **Ranks 1 and 2:** Approve programs for 2009-2011 but require utilities to seek additional approval, as appropriate, through advice letter filing updates to reflect resolution of any major uncertainties.
> **Rank 3:** Approve for 2009, but require new applications for 2010 showing a need for the programs.
> **Rank 4:** Do not approve.[44]

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[43] Exhibit 314, pp. 13-14.

[44] Exhibit 314, p. 15.

8.8. CAISO

CAISO focused its attention within this proceeding primarily on the demand response pilots proposed in the utilities' applications. CAISO supports the efforts of the utilities to conduct pilots to test the ability of demand response activities to function under the new CAISO markets. In addition, CAISO cautions against counting benefits for avoided transmission and distribution investments in the cost effectiveness analyses of current programs; CAISO argues that these benefits should not be counted until or unless the utilities are able to show how the utilities use demand response savings in their planning to avoid building new transmission and distribution.[45]

8.9. Energy Curtailment Specialists

Energy Curtailment Specialists participated on the limited issues of appropriate baseline methodologies for demand response programs and timely approval of aggregator contracts. Energy Curtailment Specialists advocates for the adoption of a 5-in-10 day baseline methodology with an optional day-of adjustment.[46] Energy Curtailment specialists also initially advocated for the approval of its contract with SCE.

8.10. CPower

CPower (formerly ConsumerPowerline) is concerned about the possibility that later contracts between a utility and a third-party aggregator would undermine aggregators' earlier contracts by offering more attractive or beneficial

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[45] CAISO Opening Brief, p. 10.

[46] Energy Curtailment Specialists Reply Brief, p. 3.

terms. In order to address this, CPower suggests that the Commission allow the amendment of existing contracts to match the terms of new contracts.[47]

8.11. Ice Energy

Ice Energy advocates for the expansion of Permanent Load Shifting, as a portion of the utilities' demand response activities.

9. Policy on Development of Emergency-triggered and Price Responsive Demand Response Activities

The utility demand response programs funded through this proceeding constitute only a portion of related demand response and dynamic pricing activities currently operating or proposed to operate in California. Additional demand response activities have been approved in separate Commission proceeding, and some continue to be funded through utility General Rate Cases, advanced metering infrastucture decisions, and other applications. The demand response funding approved in this application comprises approximately one quarter to one third of the total funding available to support demand response; the following table provides a comparison of funding authorized in this decision with the approximate total funding available:

Utility	***2009 - 011 DR Program Budgets Approved in Application A.08-06-001***	***PG&E, SCE and SDG&E 2009 - 2011 DR Program Budgets Recovered in Other Proceedings***	***Total CA IOU Estimated DR Program Budgets 2009-2011***
PG&E	$109,060,072		
SCE	$188,806,349		
SDG&E	$51,643,042		
Total	$349,509,463	$858,638,025	$1,208,147,488

Note: The Total DR Program Budget Estimate does not include $5.6 Billion for PG&E, SCE

[47] CPower Opening Brief, p. 2.

and SDG&E for the combined cost of AMI hardware

The total expected load impact of the demand response activities discussed in this decision, some of which are funded elsewhere, are as follows:

PG&E Load Impact - Application Filing (Sept. '08)
Monthly System Peak Load in July under 1-in-2 Weather Year Condition
(MWs)

	2009	2010	2011
Reliability Program			
BIP	259.8	259.8	*
OBMC/SLRP	**	**	**
Smart AC***	151.9	224.3	306.6
DWR***	200	200	200
Total Reliability Prog.	**611.7**	**684.1**	**506.6**
Price Response Program			
DBP	8.2	*	*
CPP	19.9	19.8	19.4
Smart Rate***	51.8	145	295
PeakChoice: Committed Load- DO	9.6	10.1	271.1
PeakChoice: Committed Load – DA	14.3	18.4	21.4
PeakChoice: Best Effort	12.4	31	31.6
Total Peak Choice	36.3	59.5	324.1
Total Price Response Prog.	**116.2**	**224.3**	**638.5**
Service Provider (Aggregators) Managed Prog.			
CBP	18.3	18	17.6
AMP	124.6	141.4	143.8
Total Service Provider (Aggregators) Managed Prog.	**142.9**	**159.4**	**161.4**
Other			
Permanent Load Shift (PLS)	2.1	3.9	3.9
Total Other	**2.1**	**3.9**	**3.9**
PG&E Total All DR Programs	**872.9**	**1,071.70**	**1,310.40**

Reference
PG&E 2009-2011 Demand Response Programs and Budgets amended Prepared Testimony, September 19, 2008, Table 2-1
*MWs for this group of customers are merged with the PeakChoice in this table.
**SLRP has not had a participant since 2005.
OBMC does not count towards RA and is not included in the cumulative total (around 11 MW of participation).
***Budget was not requested in this proceeding (A.08-06-003).

Note: Pursuant to D.08-04-050, PG&E filed an updated Load Impact Report on May 1 2009, which is not reflective in this table.

SDG&E Load Impact - Application Filing (Sept. 2008)
Annual Peak Day under 1-in-2 Weather Year Condition
(MWs)

	2009	**2010**	**2011**
Reliability Program			
BIP	5	5	5
OBMC/SLRP	0	0	0
Summer Saver Residential*	13	16	16
Summer Saver Small Commercial*	8	10	10
Total Reliability Prog.	**26**	**31**	**31**
Price Response Program			
CPPD - Medium C&I (20-200 kW)*	0	0	16
CPPD - Large C&I (>200 kW)*	58	60	61
CPPE	2	2	2
PTR- Residential*	0	50	95
PTR - Small C&I (<20 kW)*	0	3	8
Total Price Response Prog.	**60**	**115**	**182**
Service Provider (Aggregators) Managed Prog.			
CBP-DA	14	17	20
CBP-DO	3.5	4.2	4.9
Total Service Provider (Aggregators) Managed Prog.	**17.5**	**21.2**	**24.9**

Other			
Permanent Load Shift (PLS)	2	2	2
TI - Auto DR	8	16	24
TI - Non Auto DR	6	12	18
Total Other	**16**	**30**	**44**
SDG&E Total All DR Programs	**120**	**197**	**282**

Reference
2009-2011 MWs from Amended Application of SDG&E for Approval of DR Programs and Budgets For Years 2009 through 2011, Sept. 19, 2008, Volume IV of VI, pg 8.
2007 MWs from Amended Application of SDG&E for Approval of DR Programs and Budgets for Years 2009 through 2011, Sept. 19, 2008, Volume IV of VI, pg 18 Table KS-9.
*Budget was not requested in this proceeding (A08-06-002).

Note: Pursuant to D.08-04-050, SDG&E filed an updated Load Impact Report on May 1 2009, which is not reflective in this table.

SCE Load Impact
Top 20 Highest System Load Days under 1-in-2 Weather Year
(MWs)

	2009	2010	2011
Reliability Program			
BIP***	774.7	855.8	945.4
OBMC/SLRP	*	*	*
SDP***	529.5	533.3	537.2
AP-I	40.0	41.3	42.2
Total Reliability Prog.	**1,344.2**	**1,430.4**	**1,524.8**
Price Response Program			
DBP	16.9	16.9	16.9
CPP	*	*	*
RTP	10.2	10.5	10.9
Total Price Response Prog.	**27.1**	**27.4**	**27.8**
Service Provider (Aggregators) Managed Prog.			
CBP	46.3	48.9	51.8
DR Contracts**	106.0	170.0	210.0
Total Service Provider (Aggregators) Managed Prog.	**152.3**	**218.9**	**261.8**
SCE Total All DR Programs	**1,523.6**	**1,676.7**	**1,814.4**

Reference
2009-2011 MWs from SCE Appendices A through M, Sept. 19, 2008, Appendix F, pg 4.
* SCE did not apply LI Protocols due to the lack of ex post data, with which to perform ex ante estimates.
**SCE did not forecast service account enrollment, nor apply LI Protocols. Assumed the contractual capacity of each DR contract.
***MWs amount should be lower because of the cap in emergency program.
Note: Pursuant to D.08-04-050, SCE filed an updated Load Impact Report on May 1, 2009, which is not reflective in this table.

9.1. Price Responsive Demand Response Activities

Since 2003, this Commission has emphasized the importance of price-responsive demand response as a key component of our overall demand response policy. While emergency-triggered demand response plays an important role in improving the reliability of our grid, price-responsive demand response can lower overall wholesale electricity costs for all customers as well as help mitigate wholesale market power. Additionally, reducing consumer electricity usage during peak periods can help reduce fuel use and overall air emissions. The CAISO's implementation of its new markets makes price-responsive demand response even more important to pursue since demand response can now participate in more markets and, in the future, on a locational basis.

The development of dynamic pricing rates, such as default critical peak pricing, is consistent with our emphasis on price-responsive demand response, and we have made recent progress in this area through our utility general rate case proceedings. For example, default critical peak pricing was implemented in SDG&E's territory in 2009 for all customers with loads of 20 kilowatts or more that have advanced meters. PG&E and SCE have default critical peak pricing rates under our consideration.

The price-responsive programs adopted in this decision also play an important role in our efforts to increase price-responsive demand response. Since CAISO’s implementation of its new markets, such programs have the potential to be aligned with wholesale markets. Our 2008 Energy Action Plan Update emphasizes the importance of such alignment, noting that retail demand response programs should be modified so that they can more fully participate in CAISO's new wholesale market structure.[48]

We also believe that customers should be provided with the necessary tools so that adjustments to their electricity usage in response to price-responsive demand response programs are simple to understand and easy to implement. Effective customer education, along with automated demand response and enabling technologies, are tools that may contribute to the growth of demand response in California, and make demand response activities more effective and useful.

9.2. Emergency-triggered Demand Response

Emergency-triggered demand response activities are programs that are triggered by the utilities in response to an actual or imminent declaration by CAISO of a system emergency, or during, or in anticipation of, a local transmission or distribution emergency. Historically, emergency-triggered demand response programs have provided load reductions only when CAISO declares a Stage 2 emergency. Emergency-triggered programs have been used to maintain system reliability while avoiding other emergency responses such as rolling blackouts. The Commission has signaled its intention to emphasize price responsive programs and dynamic pricing tariffs in the future, in part in an effort to integrate demand response with the CAISO's new markets.

Currently these programs account for approximately 2,000 megawatts. In this and other recent proceedings, CAISO has sought access to these resources prior to a Stage 2 emergency. In 2008, the Commission initiated Phase 3 of

[48] Energy Action Plan – 2008 Update, February 2008, p. 14.

R.07-01-041 to examine more closely the amount and type of emergency-triggered demand response that is needed for system reliability and may appropriately be triggered in response to a system Stage 1, 2, or 3 emergency, and the amount that can or should be transitioned to price-responsive triggers more integrated with the CAISO's new markets. Phase 3 of R.07-01-041 is intended to determine the direction for emergency-triggered programs, such as the appropriate amount of capacity (in megawatts) to enroll in these programs and how to transition any excess capacity to non-emergency programs with price responsive triggers integrated with the CAISO's new markets.

Since the initiation of Phase 3, the utilities filed advice letters that were approved in Resolution E-4220, modifying the trigger for the statewide Base Interruptible Program to include a new event trigger. As a result, Base Interruptible Program events may be triggered when CAISO provides notice that a Stage 1 Emergency is imminent. As before, the Base Interruptible Program can still be triggered with a Stage 2 alert from CAISO.

In their applications, the utilities propose the expansion of several existing demand response programs, including those that currently can only be triggered in a Stage 2 CAISO Emergency. In response, DRA and CAISO raise concerns regarding the optimal size for the total interruptible programs, and urge the Commission to determine if the emergency interruptible programs should be capped between 500 megawatts and 800 megawatts. We find that reducing the amount of emergency-triggered demand response is currently under consideration in another proceeding and is beyond the scope of this proceeding, as argued by SCE. In its comments on the proposed decision in this proceeding, PG&E and other utilities argue that capping these programs at their current levels is also beyond the scope of this proceeding.[49] However, this is not the case. The scope of this proceeding includes determining which programs should be continued in 2009 through 2011, and the appropriate budgets for those programs. Modifications to the size, design characteristics, and funding of individual programs based on factors such as their cost effectiveness, flexibility and other attributes is a primary purpose of this proceeding.

In recognition of the ongoing examination of the appropriate size and role of emergency programs in R.07-01-041 Phase 3, we decline to expand existing emergency-triggered programs or adopt new emergency programs with similarly limited triggers. Instead, we cap these programs at their current enrollment (in megawatts) and funding levels pending the resolution of R.07-01-041 Phase 3, with a limited exception for the PG&E SmartAC program. If necessary, utilities may use waiting lists or other methods of tracking customer interest to assist them in maintaining programs at their current size and replacing megawatts lost from these programs through attrition. The specific requests are addressed in more detail below. As discussed below, minor changes to ensure consistency in program characteristics (such as settlement baselines) are made here, but expansion or replacement of these programs is postponed until the underlying policy issues are addressed in R.07-01-041.

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[49] Opening Comments of Pacific Gas and Electric Company on Proposed Decision, July 20, 2009. Page 7.

10. Statewide Emergency and Price Responsive Programs

Several existing demand response programs are available in the territories of all three utilities; some of these programs are emergency-triggered and others are considered price responsive. This section addresses both types of programs that are available through all three utilities.

10.1. Emergency Programs

Statewide emergency programs include the Base Interruptible Program, the Optional Binding Mandatory Curtailment program, and the Schedule Load Reduction Program. These programs, like the utility-specific emergency-triggered programs discussed in Section 11, below, are evaluated based on the principles articulated in Section 9, above.

10.1.1. Base Interruptible Program

The Base Interruptible Program requires participants to reduce their electricity usage to a pre-determined base level when the program is called. In Resolution E-4220, the Commission authorized PG&E, SCE, and SDG&E to modify their Base Interruptible Program programs so that the Base Interruptible Program can now be called when CAISO provides notice that either a Stage 1 or Stage 2 Emergency is imminent. The Base Interruptible Program can still be triggered with Stage 1 or 2 alerts from CAISO.

10.1.1.1. Utility Proposals for the Base Interruptible Program

PG&E proposes several changes to its Base Interruptible Program in 2009 through 2011. Specifically, PG&E proposes to realign the current Base Interruptible Program zones to coincide with the CAISO Local Capacity Areas to increase this program’s compatibility with MTRU and more easily allow Base

Interruptible Program resources to act as Participating Load or Proxy Demand Resource.[50] PG&E also proposes eliminating Base Interruptible Program Option B, both because no participant has ever enrolled in this option, and because the features of Option B are similar to PG&E's existing PeakChoice program.[51] PG&E does not plan to expand its Base Interruptible Program, and in fact proposes the possibility of transitioning Base Interruptible Program Option A participants into a similar option under its broader PeakChoice Program in 2011, and discontinuing the Base Interruptible Program as an independent program.[52] PG&E requests $1.2 million to fund administration of the Base Interruptible Program; incentives are addressed in another proceeding.

Unlike PG&E, SDG&E does not propose major changes to its Base Interruptible Program in 2009-2011. SDG&E seeks to expand its Base Interruptible Program during this period, and estimates that Base Interruptible Program will have 5 megawatts of capacity in 2010.[53] SDG&E requests a budget of $1,657,067, a slight increase over 2008.

SCE is not proposing any modifications to its current Base Interruptible Program (formerly its I-6 tariff). SCE expects approximately 10% growth for this program and is requesting $5,068,756 in funding for the 2009-2011 period.[54]

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50 Exhibit 201, Chapter 2, pp. 6-7.

51 Exhibit 201, Chapter 2, p. 7.

52 Exhibit 201, Chapter 2, p. 3.

53 SDG&E Exhibit 102A, p. 31.

54 SCE Amended Testimony, p. 35.

10.1.1.2. Party Positions

DRA recommends that the Commission limit the Base Interruptible Program for all three utilities to one year of funding, and freeze enrollment at current levels.[55] DRA also questions the PG&E claim that it can transition most of its Base Interruptible Program customers to PeakChoice; DRA notes a lack of evidence that PG&E has worked with its customers to educate them about this possible change or show them that customers are willing to make such changes.[56]

CAISO supports the DRA proposal to approve and fund the Base Interruptible Program for one year only.[57] Additionally, CAISO urges the Commission to not approve any additional enrollment or recruitment into this program until the Commission makes a decision on how the Base Interruptible Program will be treated under the Commission's Resource Adequacy program.[58] In response to DRA and CAISO, SCE states that "there is no legitimate support in the record of this proceeding for limiting Base Interruptible Program to only one year in duration or freezing current participation levels."[59]

CLECA expresses concerns about the PG&E proposal to transition participants in the Base Interruptible Program to a similar option as the PeakChoice program. Generally, participants in PeakChoice may choose to change certain terms of their demand response participation at intervals, sometimes as often as monthly. CLECA contends that PG&E's attempt to

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[55] DRA Opening Brief, p. 30.

[56] DRA Protest, September 29, 2008, p. 8.

[57] CAISO Reply Brief February 11, 2009, p. 2.

[58] CAISO Comments to Utility Applications, July 9, 2008, p. 5.

subsume Base Interruptible Program into PeakChoice will create customer confusion and "water down those elements of the [Base Interruptible] program which are its strength."[60] CLECA argues that the Commission should not evaluate the Base Interruptible Program on the basis of its ability to be integrated into the CAISO's new markets.[61] CLECA asserts that there are good reasons to maintain emergency programs such as the Base Interruptible Program and that the Commission should "resist the temptation to attempt a force fit of [the Base Interruptible Program] into MRTU."[62] In support of its recommendation that the Commission maintain the Base Interruptible Program as a reliability program triggered by system emergencies, CLECA asserts that many of its members "are not particularly interested in tracking market prices for electricity or placing energy procurement above producing their product,"[63] and might discontinue participation in demand response programs if the program requirements change.

TURN notes the low enrollment in SDG&E's Base Interruptible Program, and recommends maintaining the SDG&E program at its current level with a reduced budget of $993,000.

10.1.1.3. Discussion

According to the cost effectiveness numbers provided by the utilities, the Total Resource Cost test results for the Base Interruptible Program are greater

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59 SCE Reply Brief, p. 22.

60 CLECA Opening Brief, p. 5.

61 CLECA Reply Brief, p. 4.

62 CLECA Opening Brief, p. 6.

63 CLECA Opening Brief, p. 7.

than one for all three companies.[64] Based on these estimates, the Base Interruptible Program appears to be cost effective statewide. We decline to approve the expansion of the SCE and SDG&E Base Interruptible Programs, as requested. Though we are capping the enrollment in these programs at their current megawatt level, we approve some funding for program-specific marketing activities in order to allow utilities to replace megawatts lost through customer turnover.

PG&E's proposed transition of Base Interruptible Program participants into PeakChoice does not appear to be fully developed at this time. As noted by DRA, it is not clear whether PG&E has studied the willingness of its customers to enroll in PeakChoice. PG&E states that it will transition Base Interruptible Program resources "into the PeakChoice program (with similar options)."[65] However, it is unclear from this statement if PG&E would transition Base Interruptible Program into a PeakChoice program in which the Base Interruptible Program would be triggered by non-emergency conditions, or whether Peak Choice would have a Base Interruptible Program option that retains its emergency-only trigger. For these reasons, we deny PG&E's request to transition Base Interruptible Program customers to PeakChoice at this time, and we also deny the PG&E request to be allowed to terminate the Base Interruptible Program via advice letter in the future. Given the size and importance of the Base Interruptible Program, any significant changes should be carefully reviewed though a formal Commission proceeding.

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64 Base Interruptible Program TRC results -- SCE: 1.11; PG&E: 1.03; SDG&E: 1.48.

65 Exhibit 201, Chapter 2, p. 7.

The Base Interruptible Program is not well integrated with the CAISO's new markets, though the recent change that allows it to be called in advance of a Stage 1 emergency does increase the flexibility of the program. Given that information on the optimal design of demand response programs under the CAISO's new markets is likely to develop gradually over the next several years, and that the amount of emergency demand response needed to ensure reliability has not yet been determined in Phase 3 of R.07-01-41, we see no benefit to requiring an additional review of the Base Interruptible Program before approving the program for years beyond 2009; it is reasonable to approve a three-year budget for this program for the complete 2009-2011 period. We establish the following budget amounts based on the lower of 2008 actual spending or 2009 proposed funding. We order PG&E to end its Base Interruptible Program Option B within 30 days of the effective date of this decision. The following total budgets for 2009-2011 are approved for the utilities' Base Interruptible Programs:

	2009-2011 Requested Budget	2009-2011 Authorized Budget
PG&E	$1,242,000	$800,000
SDG&E	$1,657,067	$1,475,423
SCE	$5,068,756	$4,702,374[66]

[66] This number is based on the SCE 2008 total program expenditures included in the January 2009 monthly spending reports, with marketing costs removed.

These budgets and total budgets for 2009-2011 throughout this decision include the amounts authorized in the Bridge Funding decision and already spent during 2009.

10.1.2. Optional Binding Mandatory Curtailment Program

The Optional Binding Mandatory Curtailment Program is a voluntary program that exempts participating customers from rotating outages if they commit to reducing power on a particular distribution circuit by at least 15% upon notification of a local or statewide electrical emergency. No financial incentives are paid to program participants

10.1.2.1. Utility Proposals

PG&E's requests that its Optional Binding Mandatory Curtailment Program and Pilot Optional Binding Mandatory Curtailment Program be consolidated into a single program, with a total budget of $138,000.

SCE proposes to maintain its current level of customer enrollment in the Optional Binding Mandatory Curtailment Program (currently 12 customers with an associated reduction of approximately 9 megawatts) and its current budget level for this program, $197,994.

SDG&E maintains an Optional Binding Mandatory Curtailment Program which currently has no participants enrolled. For this reason, SDG&E does not request a budget for the Optional Binding Mandatory Curtailment Program.

TURN recommends that the Commission eliminate funding for the Optional Binding Mandatory Curtailment Program and close the program, or, if the program remains open, that administrative costs of the program should be borne by program participants. No other parties took a position on the Optional Binding Mandatory Curtailment Program for any utility.

10.1.2.2. Discussion

All three utilities propose maintaining their Optional Binding Mandatory Curtailment Programs at their current, relatively low levels. TURN's recommendation that this program's administrative costs should be charged directly to program participants is inconsistent with our treatment of other demand response programs, and we decline to adopt it. Rather than require the utilities to transfer Optional Binding Mandatory Curtailment Program participants to another program, we authorize the continuation of this program at the requested funding levels. We also authorize PG&E to combine its Optional Binding Mandatory Curtailment Program and Pilot Optional Binding Mandatory Curtailment Program, as requested. The authorized budgets are as follows:

	2008-2009 Requested Budget	2008-2009 Authorized Budget
PG&E	$138,000	$138,000
SDG&E	$0	$0
SCE	$197,994	$197,994

10.1.3. Scheduled Load Reduction Program

The Scheduled Load Reduction Program was established in January 2001, pursuant to legislation adopted by the state during the energy crisis. Program participants are allowed to choose time periods during which they will reduce their load by at least 100 kilowatts or 1%, and are paid an incentive for these reductions. This program is legislatively mandated and so cannot be discontinued.

10.1.4. Utility Proposals

PG&E includes the Scheduled Load Reduction Program with its Optional Binding Mandatory Curtailment Program, and does not request a separate budget for this program.

SCE and SDG&E list their Scheduled Load Reduction Program separately, but both state that they do not have participants currently enrolled in this program. SDG&E does not request funding for the Scheduled Load Reduction Program in this proceeding; a minimal budget for this program was approved in an earlier SDG&E rate case (see D.08-02-034). SDG&E also notes its intention to minimize expenditures while maintaining this program in the 2009-2011 period. SCE requests a minimal budget in this proceeding to continue to support the availability of this program in case there is future interest by customers.

No other parties took a position on the Scheduled Load Reduction Program for any utility.

10.1.4.1. Discussion

All three utilities propose maintaining the availability of their Scheduled Load Reduction Program, in compliance with the legislative mandate for this program. There are no objections to continuing this program, and only SCE requests funding in this proceeding. We authorize the continuation of the Scheduled Load Reduction Program at the requested funding levels, as follows:

	2008-2009 Requested Budget	2008-2009 Authorized Budget
PG&E	$0	$0
SDG&E	$0	$0
SCE	$52,995	$52,995

10.2. Price Responsive Programs

Price responsive programs are generally triggered by high temperatures or the wholesale market price of electricity. The utilities may notify customers that a program is being triggered one day in advance of the event day (day-ahead), or on the same day as the event (day-of). These programs include the Demand Bidding Program, the Capacity Bidding Program, the Critical Peak Pricing tariffs, and the Real Time Pricing tariffs. The Peak Time Rebate tariffs do not require funding in this proceeding and so are not discussed here.

10.2.1. Demand Bidding Program

Under the Demand Bidding Program, participating customers may submit bids to voluntarily reduce load when a Demand Bidding Program event is called, in return for payments if their bid is accepted and the load reduction is delivered.

10.2.1.1. Utility Proposals

PG&E proposes to end its Demand Bidding Program after 2009, and transition participating customers into a similar option under its PeakChoice Program. For this reason, PG&E requests a total of $1 million in funding for this program, for 2009 only. PG&E estimates the benefit to cost ratio of this program in its service territory using the Total Resource Cost test as being over 2, suggesting that the program is cost effective for PG&E.

SDG&E seeks to eliminate this program, which it finds to be duplicative and ineffective.[67] SDG&E has 366 accounts enrolled in its Demand Bidding Program for a total load of approximately 11.5 megawatts as of December 2008.

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[67] SDG&E Opening Brief, p. 53.

SDG&E plans to transition its Demand Bidding Program participants onto its default Critical Peak Pricing, and to hold a workshop for these customers to explain the transition. Because SDG&E requests to discontinue this program, it does not request funding for it during 2009-2011.

SCE proposes to continue its Demand Bidding Program through 2009 and into early 2010, and to then transition Demand Bidding Program customers to its Energy Options Program. SCE estimates that in 2009-2011, it will have over 1,000 customers enrolled in the Demand Bidding Program, for approximately 35 megawatts of load. SCE estimates the cost effectiveness of the Total Resource Cost test at approximately 0.81; this suggests that the program is close to being cost effective, but may not be at this time. To support the Demand Bidding Program, SCE asks for a total of $259,939 for 2009-2011, with $254,939 for 2009 and $5,000 for early 2010. After this, SCE does not anticipate the need to fund this program separately from Energy Options, to which former Demand Bidding Program participants would be transitioned.

10.2.1.2. Other Party Positions on the Demand Bidding Program

In its testimony and briefs, DRA assigns the Demand Bidding Program Rank 2 in its ranking system described in Section 8.7, above. DRA suggests that the Commission approve the Demand Bidding Program for 2009-2011, but require all three utilities to file advice letters during this period to make it more uniformly cost effective across the state.[68]

[68] DRA Opening Brief, pp. 31-32.

10.2.1.3. Discussion

PG&E's Demand Bidding Program has one of the highest estimated benefit to cost ratios of any price responsive programs. In addition, the proposed transition of Demand Bidding Program customers into PeakChoice raises some concerns with tracking the load impact and cost of each option. Because PeakChoice is a relatively new program and offers extensive flexibility by allowing customers to select from dozens of option bundles, it is complicated to analyze the program. Until more historical data are available for use in developing load impact estimates for PeakChoice, it is premature to transition Demand Bidding Program customers into PeakChoice. PG&E also has not provided a detailed plan for transitioning customers from Demand Bidding Program to PeakChoice, so it is unclear whether such a transition would be successful in maintaining the Demand Bidding Program's load impact. For these reasons, we do not authorize PG&E to discontinue this program at the beginning of 2010. The budget requested by PG&E for 2009 is comparable to the reported expenditures for 2008, and provides a reasonable annual amount for PG&E's Demand Bidding Program during 2009-2011. We adopt a three-year budget of approximately $3 million for this program, as specified below.

SDG&E seeks to eliminate this program, and has provided a plan for transitioning its participants to another demand response program, Default Critical Peak Pricing, in order to retain the load reduction currently available through the Demand Bidding Program. It is reasonable to approve the requested transition to take place on or before January 1, 2010. Because SDG&E's program is currently funded through D.08-12-038 on a month-to-month basis, some budget for this program will be necessary until the transition is completed, but funding will not be necessary during 2010 and 2011.

Unlike PG&E, the cost effectiveness estimate for SCE's Demand Bidding Program is less than one, implying that the program may not be cost effective in its current form. In addition, SCE has provided a plan for transitioning its participants into its Energy Options Program in order to retain the load reductions currently available through this program.

The proposed Energy Options Program is new and, like PG&E's cafeteria-style demand response program, it offers customer multiple options for certain terms. However, Energy Options has fewer possible options than PeakChoice, and appears easier to analyze. Given that we have fewer concerns about analysis of this program than PeakChoice, that SCE's Demand Bidding Program may not be cost effective in its current form, and that SCE has a plan for transitioning its customers into a new program while retaining their load reduction, it is reasonable to approve SCE's proposal to discontinue its Demand Bidding Program in early 2010. For this reason, we approve SCE's proposed budget for 2009 and 2010, and its proposal to transition participants into the Energy Options Program in early 2010.

DRA raises a concern that the cost effectiveness results for the Demand Bidding Program vary in different utility service territories. As DRA notes, this may be due to differences in cost effectiveness methodologies or in program design (such as differences in incentive levels) and administration, and could be addressed through increased reporting requirements and program improvements during the 2009-2011 period. We decline to adopt the DRA recommendation to require all three utilities to file advice letters detailing their progress in increasing the cost effectiveness of these programs and transitioning them to perform within the CAISO's new markets. This is unnecessary given that we are approving the SDG&E and SCE requests to transition their participants to other programs, and that the PG&E Demand Bidding Program appears to be cost effective based on current estimates.

We approve the following budgets for the Demand Bidding Program in 2009-2011:

	2009-2011 Requested Budget	2009-2011 Authorized Budget
PG&E	$1,072,000	$3,216,000
SDG&E	$492,000	$492,000
SCE	$259,939	$259,939

10.2.2. Capacity Bidding Program

Under the Capacity Bidding Program, participating customers commit to providing a particular amount of load reduction, which may vary each month, and receive capacity payments for the elected amount of load reduction. Participants also receive an energy payment based on the kilowatt-hour reduction during a called event. The capacity bidding program contains a day-ahead option, through which participants may nominate their load reduction for the next day, and a same day (referred to as "day-of") option, in which load is called the day of the event. Parties that do not deliver at least 50% of their elected load reduction under this program are subject to penalties, and, as with most demand response programs, participants must have appropriate metering to enroll.[69]

[69] D.08-12-038 provides $128,000 for PG&E, $89,500 for SCE, and $77,000 for SDG&E for per month the Capacity Bidding Program until the end of 2009 or until a subsequent decision provides funding for the remainder of 2009-2011.

10.2.2.1. Utility Proposals

Currently, PG&E allows direct customer enrollment in its Capacity Bidding Program, in addition to customer participation through its aggregator managed contracts. PG&E proposes to discontinue direct customer enrollment in its Capacity Bidding Program, and continue this program only through its aggregator contracts. PG&E requests a total of $6.6 million for the Capacity Bidding Program during 2009-2011.[70] PG&E currently has no participants enrolled in this program directly through the utility; all existing participants have been enrolled through aggregators. PG&E estimates the benefit to cost ratio of the day-ahead Capacity Bidding Program option as 0.50 and of the day-of notification option as 0.77, for an overall benefit to cost ratio of 0.61. By PG&E's report, this program provided approximately 18 megawatts of load reduction in 2008.

Like PG&E, SDG&E currently allows direct customer participation in its Capacity Bidding Program, as well as participation through a third-party aggregator. SDG&E recommends expansion of its Capacity Bidding Program during the 2009-2011 period. SDG&E estimates that the Capacity Bidding Program has a load reduction potential of approximately 21 megawatts, and requests approximately $6.8 million over the three-year cycle. SDG&E estimates the benefit to cost ratio of the day-ahead Capacity Bidding Program option as 1.45 and of the same-day notification option as 1.26.

SCE proposes to continue its Capacity Bidding Program through 2009 and into early 2010, and to then transition participating customers to its cafeteria-

[70] Aggregator managed portfolio contracts were approved in previous proceedings.

style program, the Energy Options Program. SCE asserts that combining this program into the Energy Options Program along with the Demand Bidding Program, described above, would provide customers with more flexibility and increase the program's compatibility with the CAISO's new markets. SCE requests a budget of $812,299 for 2009 and early 2010, with $638,299 for 2009 and $174,000 for 2010. SCE estimates the overall cost effectiveness of its Capacity Bidding Program is 0.86; SCE did not initially provide separate cost effectiveness analysis for its day-ahead and day-of options. After early 2010, SCE does not anticipate the need to fund this program separately from Energy Options, to which former Demand Bidding Program participants will be transitioned.

10.2.2.2. Party Positions on the Capacity Bidding Program

TURN argues that the Capacity Bidding Program should be discontinued for both SDG&E and PG&E. TURN notes the relatively low benefit to cost ratio of for PG&E (0.61 overall) in recommending that PG&E's Capacity Bidding Program funding request be denied. Both DRA and TURN suggest that the SDG&E estimate of potential load reduction through the Capacity Bidding Program is unrealistically high, and TURN recommends that we deny funding for SDG&E's program.

10.2.2.3. Discussion

Like the Demand Bidding Program, the Capacity Bidding Program is currently offered statewide, and its enrollment, funding, and estimated cost effectiveness vary by utility service territory.

PG&E requests approval to cease enrolling customers directly in the Capacity Bidding Program, and to allow only third-party aggregators to enroll customers in its Capacity Bidding Program in 2009-2011. Given that all PG&E

customers currently enrolled in this program have been enrolled through aggregators, it is reasonable to continue customer enrollment under the management of aggregators. As noted by TURN and DRA, the benefit to cost ratio of this program, and especially the day-ahead option, are far below one, so it does not appear that this program is cost effective for PG&E at this time. However, there is value to having this program or a similar option operate statewide, and we hope that the benefit to cost ratio may be improved in the future. Given the relatively low benefit to cost ratio of PG&E's program, however, it would not be reasonable to fully fund this program as requested by PG&E. Specifically, it is reasonable to expect that the funding spent on administrative expenses for a program should not be greater than the amount spent on incentives. For this reason, we will continue the PG&E program as an aggregator-managed program, but with a lower budget than proposed by PG&E. PG&E requests $4,623,609 for administrative activities, and $1,564,685 for incentives. We authorize a total funding of $3,615,076 for PG&E's Capacity Bidding Program for 2009-2011, as noted below.

SDG&E seeks to expand this program, and the benefit to cost ratios for both its day ahead and day of options are above one. It is not clear whether the estimates of program potential load impact for this program provided by SDG&E are realistic, but it is clear that both enrollment in this program and the load drop associated with it have increased in the recent past, and it appears that there is interest in this program among customers in the SDG&E service territory. For 2009 only, the estimated administrative costs for this program exceed the forecast incentives; this is not the case for the budget requests for 2010 and 2011. Consistent with our policy that the administrative costs should not exceed the incentive costs for a program in a given year, we reduce SDG&E's

proposed budget for this program by approximately $400,000, the amount of the excess administrative costs for 2009. Given that this program appears to be cost effective, it is reasonable to approve the SDG&E request to expand this program. We authorize total funding of $6,426,173 for this program during 2009-2011, the full request less the excess administrative costs for 2009, as noted below.

SCE proposes to retain its Capacity Bidding Program only through early 2010, when it expects to transition its participating customers to its Energy Options Program. The cost effectiveness estimates for SCE's Demand Bidding Program are less than one, though they appear to be slightly higher than the ratios for PG&E's program. In addition, SCE has provided a plan for transitioning its participants into its Energy Options Program in order to retain the load reductions currently available through this program. As discussed above, the Energy Options Program is new but appears relatively easy to analyze. Given that the Capacity Bidding Program may not be cost effective in its current form, and that SCE has a plan for transitioning its customers into a new program while retaining their load reduction, it is reasonable to approve SCE's proposal to discontinue its Capacity Bidding Program in early 2010. For this reason, we approve SCE's proposed budget of $812,299 for 2009 and early 2010, and its proposal to transition participants into the Energy Options Program in early 2010.

In the future, all three utilities are required to report results separately for their day-ahead and day-of Capacity Bidding Program options. We approve the following budgets for the Capacity Bidding Program in 2009-2011:

	2009-2011 Requested Budget	2009-2011 Authorized Budget

PG&E	$6,600,000	$3,615,076
SDG&E	$6,831,983	$6,426,173
SCE	$ 812,299	$ 812,299

10.2.3. Critical Peak Pricing

Critical Peak Pricing Programs, variations of which are available through all three utilities, applies an increased rate to electricity consumption during certain high usage period in which program events are called. During non-event periods, participants in Critical Peak Pricing receive a lower rate to offset the increased rate during events. [71] Events may be called on summer weekdays, and last from noon to 6:00 p.m. The higher event rate is intended to induce customers to lower their electricity use during these critical peak events. There is no penalty for failure to reduce usage during peak times other than the application of the high peak rate for the electricity used. Unlike some other demand response programs, customers receive the benefits of program participation directly through the tariffed rate applied during non-peak hours; for this reason, the Critical Peak Pricing Program does not require calculation of an estimated baseline and associated load drop during events for customer settlement purposes.[72]

10.2.3.1. Utility Proposals

PG&E's Critical Peak Pricing Program applies a high premium rate for energy usage from 3:00 p.m. to 6:00 p.m. on event days, and a slightly lower

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[71] D.08-12-038, the Bridge Funding Decision in this proceeding, provides $102,000 for PG&E, $12,500 for SCE, and $15,000 for SDG&E for the existing Critical Peak Pricing programs per month until the end of 2009 or until a decision is reached providing funding for the remainder of 2009-2011.

[72] Load Impact calculations for resource adequacy and other purposes are still required.

premium rate from noon to 3:00 p.m. on those days. PG&E may call a maximum of 12 events per year. In D.08-07-045, the Commission ordered PG&E to propose a default Critical Peak Pricing Tariff (the existing tariff is voluntary) to be in place by May 2010. In its application, A.08-06-001, PG&E proposes to continue this program with a budget of $3.5 million during 2009-2011. PG&E estimates the TRC Test benefit to cost ratio of its Critical Peak Pricing Program at approximately 1.31.

SDG&E has two Critical Peak Pricing Tariffs, its Default Critical Peak Pricing (CPP-D) and its Emergency Critical Peak Pricing (CPP-E). The Emergency Critical Peak Pricing program is discussed in Section 11.3.1, below. SDG&E expects participation in its CPP-D tariff to expand during 2009-2011, but does not request funding for this activity in this proceeding because its CPP-D is funded through the company's General Rate Case. SDG&E estimates that its CPP-D tariff will have a load reduction potential of approximately 60 megawatts in 2010, and reports the tariff's TRC benefit to cost ratio as 2.8.

SCE currently has two Critical Peak Pricing tariffs, one for customers with a demand between 200 kilowatts and 500 kilowatts (the CPP-Volumetric Charge Discount (VCD) tariff), and another for customers with demands of over 500 kilowatts (CPP-Generation Capacity Charge Discount (GCCD) tariff). In its recent general rate case, SCE requests to create a default Critical Peak Pricing tariff that would apply to all commercial and industrial customers with a demand of 200 kilowatts or more. In this proceeding, SCE requests $2,641,460 to cover expenses related to its Critical Peak Pricing tariffs during 2009-2011. SCE estimates the cost effectiveness ratio of this program at 0.69.

10.2.3.2. Other Party Positions

TURN questions the need for PG&E to receive Critical Peak Pricing funding in this proceeding, because PG&E has authority to record incremental costs associated with the implementation of dynamic pricing rates, including Critical Peak Pricing, in a memorandum account. If the Commission decides to authorize funding in this proceeding, TURN recommends authorizing a budget of $2.124 million for 2009-2011 to reflect the 2006-2008 recorded costs. PG&E did not address TURN's concerns related to Critical Peak Pricing funding in its briefs. No parties oppose the Critical Peak Pricing proposals of SCE and SDG&E, though CAISO suggests that the Critical Peak Pricing tariff should be transitioned from the current weather-sensitive design to a more price responsive design that varies prices based on electricity costs at different times.

10.2.3.3. Discussion

Similar versions of Critical Peak Pricing are available statewide to customers of all three utilities. All three utilities propose to transition from offering these tariffs on a voluntary basis to making them the default for certain groups of customers, who could then opt out of the tariff if they choose to do so. The utilities in general propose making their Critical Peak Pricing tariffs more consistent with the CAISO's new markets. According to the cost effectiveness estimates, this tariff is cost effective for PG&E and SDG&E, though apparently not for SCE.

The Commission has expressed its support and preference for dynamic pricing in several decisions in the past four years. Default Critical Peak Pricing has already been ordered for PG&E and SDG&E, and is under consideration for SCE. It is likely that enrollment in these programs will increase as they become default tariffs for certain groups of customers. It is not necessary to approve funding for SDG&E in this proceeding, so we approve the continuation of its Critical Peak Pricing Program with funding authorized in its General Rate Case Decision, D.08-02-034. TURN's argument that funding for PG&E should not be authorized here for PG&E because it already has the ability to record costs for this program in a memorandum account is not persuasive; funding for Critical Peak Pricing has been authorized in the demand response-related proceeding in the past and is reasonably requested and authorized here for 2009-2011. This program appears to be cost effective for PG&E, and it is reasonable to avoid the funding uncertainty that would be created by deferring the decision on funding to another proceeding. At the same time, we recognize that the funding for Critical Peak Pricing authorized in this decision should be discontinued if a new default Critical Peak Pricing program is adopted in A.09-02-022. Until such changes may be made, however, we approve PG&E's request for $3.5 million for its Critical Peak Pricing tariff in 2009-2011; this funding will end if funding for Critical Peak Pricing is approved in A.09-02-022. The only Critical Peak Pricing Tariff that does not appear to be cost effective based on the information contained in these applications is that of SCE, but no parties have objected to the continuation of SCE's Critical Peak Pricing program or to the company's proposal to transition the program to a default tariff. We expect that this activity may become more cost effective for SCE as it becomes a default rate for many customers, and we approve the requested budget of $2.2 million for 2009-2011.

We approve the following budgets in this proceeding for Critical Peak Pricing in 2009-2011:

	2009-2011 Requested Budget	2009-2011 Authorized Budget

PG&E	$3,514,000	$3,514,000
SDG&E	$0	$0
SCE	$2,641,259	$2,641,259

10.2.4. Real Time Pricing

SCE offers a program that it refers to as "Real Time Pricing." Under SCE's Real Time Pricing program, the price of electricity for specific times of day is set based on the maximum temperature recorded the previous day. The prices are not based on wholesale market prices. SCE requests approximately $70,000 in this proceeding to administer Real Time Pricing. SCE estimates the TRC benefit to cost ratio of its Real Time Pricing Program at 1.08, meaning that this program may be cost effective in the SCE service territory. PG&E and SDG&E do not request funding for a similar program.

10.2.4.1. Other Party Positions

DRA suggests that the SCE Real Time Pricing tariff is not cost effective, though it appears from the SCE analysis that it is cost effective under the analytical scenarios provided in the utility's testimony.[73] As in the case of Critical Peak Pricing, CAISO suggests that the Real Time Pricing tariff should be transitioned from the current weather-sensitive design to a more price responsive design that varies based on electricity costs at different times.

10.2.4.2. Discussion

Real Time Pricing has already been adopted by this Commission for SCE's service territory, and only SCE requests administrative funding within this proceeding. Real Time Pricing appears to be cost effective for SCE. It is

[73] SCE Exhibit 1, pp. 219-220.

reasonable to provide administrative support for Real Time Pricing as requested by SCE, and we approve the company's request for $70,000, as specified below:

	2008-2009 Requested Budget	2008-2009 Authorized Budget
PG&E	$0	$0
SDG&E	$0	$0
SCE	$70,419	$70,409

11. Individual Utility Programs

In addition to the statewide programs discussed in Section 10, each utility has both emergency-triggered programs and price responsive programs that are approved to operate solely in their own service territory. Those programs are discussed below.

11.1. PG&E

11.1.1. SmartAC

SmartAC is an emergency-triggered program specific to PG&E; this program was formerly the Air Conditioning Direct Load Control Program. The SmartAC Program provides residential and small business customers with an incentive for temporary disconnection of their air conditioner's electrical load during peak periods. The SmartAC program and budget were approved by the Commission on February 14, 2008, in D.08-02-009, which approved a settlement agreement among PG&E, DRA, and TURN allowing PG&E to expand its SmartAC program to approximately 305 megawatts of load reduction by June 1, 2009. The estimated TRC benefit to cost ratio for this program is 1.53, implying the program may be cost effective. PG&E does not request program changes or budget for this program in this application. Rather than capping the SmartAC program at its current size in conformance with the policy adopted in this decision for other emergency-triggered programs, PG&E should adhere to the expanded size authorized and funded in D.08-02-009. In addition, we encourage PG&E to explore ways to begin transitioning this air conditioner cycling program to use more price responsive triggers.

11.1.2. SmartRate

The SmartRate Program is a price-responsive program similar in structure to the Critical Peak Pricing tariffs. SmartRate offers discounts to residential and small commercial customers during non-SmartRate event days in exchange for higher on-peak energy charges during the SmartRate high-price hours. PG&E may recruit SmartAC customers for the SmartRate program because the enabling technology used in SmartAC can be used as a tool to automate customers' participation in SmartRate events. The SmartRate program and budget were approved in July 2006 in D.06-07-027. The estimated TRC benefit to cost ratio for this program is 0.63, well below the cost effective level, but it is possible that enrollment of SmartAC customers in the SmartRate program may increase the load reductions due to the program along with the program's cost effectiveness. PG&E does not request program changes or funding for SmartRate in this application.

11.1.3. PeakChoice

PG&E's PeakChoice program, formerly called the PG&E Cafeteria-style Menu Program, allows customers to choose from several program characteristics such as amount of load reduction, event window and duration, notification time, and number of consecutive events that may be called for the customer. This flexibility is intended to allow individual customers to tailor their demand response commitments to meet their own needs. In this application, PG&E proposes to modify event notification time of non-day-of options from 12 noon to no later than 2:00 p.m., the day preceding an event, one hour after the expected 1:00 p.m. CAISO price posting time, to align with CAISO markets.[74] PG&E estimates the benefit to cost ratio of PeakChoice at 1.39. PG&E requests a total of $16.9 million for this program for 2009-2011.

11.1.3.1. Other Party Positions on PeakChoice

TURN objects to the large increase in funding for this program compared to its funding in previous years, and particularly objects to the large amount of funding requested for administrative purposes.[75] DRA classifies PeakChoice in its Rank 2 category, supporting its continuation with some restrictions. SF Power recommends that the Commission require PG&E to allow aggregators to enroll customers in PeakChoice, in order to provide customers with more flexibility than is currently offered in the main PG&E program open to aggregators, the Capacity Bidding Program.[76]

11.1.3.2. Discussion

PG&E's PeakChoice program is quite complex to analyze, given the many options available to customers, and it is also fairly new, having been approved in Resolution E-4127 on February 28, 2008. Based on the preliminary estimates of cost effectiveness, it appears that PeakChoice may be cost effective, and PG&E is making changes to the program to enable it to function better within the CAISO's new markets. By design, different options under PeakChoice have different program characteristics, making the program fairly flexible and able to

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[74] Under the new market rules, the CAISO will be posting the day-ahead prices by 1:00 p.m.

[75] TURN Opening Brief, p. 73.

[76] SF Power Opening Brief, pp. 5-9.

be called under a variety of circumstances. It is reasonable to continue the PeakChoice program for these reasons. We also approve PG&E's request to modify event notification time from 12 noon to no later than 2:00 p.m. the day preceding an event to align with CAISO markets.

The forecasted expenditures for PeakChoice in 2008 were approximately $2.8 million; as noted by TURN, total estimated costs of this program from its adoption in 2007 through the end of 2008 were approximately $4 million. These numbers are much lower than the $16.9 million requested by PG&E for this program in its application. PG&E does not provide sufficient rationale for such a large budget request.

Part of PG&E's planned expansion of this program was to transition participants in the Base Interuptible Program and the Demand Bidding Program into PeakChoice starting in 2010. In Section 10.2.1.3, we reject the requested transition, and increase the budget for the Demand Bidding Program by $2 million to reflect the ongoing costs of the Demand Bidding Program. It is reasonable to reduce the proposed PeakChoice budget by at least a commensurate amount.

In addition, as TURN notes, PG&E's proposed administrative costs for this program are extremely high compared to the estimated costs of incentives under the program. As discussed above with respect to PG&E's Capacity Bidding Program, it is reasonable to expect that administrative expenses for a program should not be greater than the amount spent on incentives. We approve a total budget for 2009-2011 of $9 million, which allows for some growth of the program over 2008 forecast levels. Initial administrative costs for PeakChoice also included costs associated with developing a new program, including implementation of new information technology and other systems; such one-time startup costs should no longer be necessary, and the decreased budget both reflects and should encourage a decrease in future administrative costs compared to during program implementation.

In its application, PG&E does not suggest opening the PeakChoice program to aggregators. This is not consistent with SCE's request to open its Energy Options Program, and is not consistent with the current Commission policy decision allowing aggregators to participate in SCE's Capacity Bidding Program. In its comments on the proposed decision, PG&E objects to the possibility of opening this program to aggregators, estimating that doing so would cost approximately $2 million and take up to 12 months to implement. These numbers are not supported in the record, and the cost estimate for redesigning information technology and other systems is equal to the amount initially requested to develop information technology systems for the PeakChoice program as a whole. Still, it is not clear whether the benefits of a potential increase in enrollment from opening this program to aggregators would outweigh the costs required to modify the program to support this change. We decline to open this program to aggregators at this time, and will revisit this issue in our next evaluation of the PeakChoice program.

11.1.4. Business Energy Coalition/ABEC

The Business Energy Coalition Program is targeted to "hard to reach" customers thought to be unlikely to enroll in other demand response activities. Consistent with past Commission guidance, PG&E is required to transition participants in the Business Energy Coalition Program to programs in which incentives are tied to performance, and recent changes in the Business Energy Coalition require that incentive payments made through this program are based on performance relative to the current program baseline. In the 2006-2008 time period, PG&E spent approximately $13 million on the Business Energy Coalition.

In the 2009-2011 time period, PG&E proposes splitting the Business Energy Coalition into two related programs. Under this proposal, PG&E would maintain the Business Energy Coalition outside of San Francisco with some minor modifications, and transition Business Energy Coalition participants within San Francisco into an Auto Business Energy Coalition (ABEC) program utilizing automated demand response capabilities to enable the program to provide immediate load reduction in response to localized system emergencies. The goal for ABEC is to gain an automated demand response capability to curtail 20 megawatts when the program is called in times of high temperatures within San Francisco. PG&E recommends the following modifications to the Business Energy Coalition and ABEC: the option of a different baseline for settlement, the option of a two-tiered load reduction commitment under ABEC (lower for mild event days, higher for severe weather days), the addition of a price trigger to both the Business Energy Coalition and the ABEC, and the ability to call the ABEC by local curtailment area. PG&E requests a budget of approximately $15 million for both the Business Energy Coalition ($5 million) and ABEC ($10 million) in 2009-2011.

PG&E estimates a benefit to cost ratio for Business Energy Coalition at 0.17 and for ABEC at 0.1. PG&E states that the Business Energy Coalition programs are worth continuing despite their low cost effectiveness estimates because they meet several of the other factors for program acceptance listed above, such as the programs' flexibility, locational value, customer acceptance, and environmental benefits.

11.1.4.1. Other Party Positions

DRA and TURN oppose the Business Energy Coalition and ABEC programs, largely due to their low benefit to cost ratios.[77] DRA asserts that the Business Energy Coalition and ABEC provide few benefits beyond those captured in the cost effectiveness analysis ratios.[78] TURN argues that any additional benefits "are not specific to the BEC program,"[79] in other words, that other Demand Response programs offer the same advantages without the high costs.

SF Power argues that funding for the ABEC program should be conditioned on the load reduction for that program fully or partially replacing the generation capacity that would otherwise be needed from the Potrero Power Plant.[80] Through this requirement, SF Power hopes to hasten the closure of that power plant.

11.1.4.2. Discussion

Overall, it appears that the Business Energy Coalition and ABEC programs do provide some benefits, but they do so at a very high cost. Even using very favorable assumptions for improved performance in 2009-2011, it is extremely unlikely that these programs would become cost effective over the next several years. The non-cost effectiveness benefits cited by PG&E in support of this program, such as locational value and flexibility, are not unique to the Business Energy Coalition programs, and are not sufficient to support continuation of

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[77] DRA Ex. 314; TURN Ex. 418, pp. 11-12.

[78] DRA Reply Brief, p. 12.

[79] TURN Reply Brief, p. 12.

[80] SF Power Opening Brief, pp. 10-13.

these programs, which have had ample time to demonstrate their ability to provide benefits at a reasonable cost, and have failed to do so. PG&E's request to continue the Business Energy Coalition and ABEC programs is denied, along with all funding requested to support these programs, including their $15 million budgets and associated funding for evaluation, measurement, and verification of the programs beyond 2009. We direct PG&E to end this program 90 days from the effective date of this decision, and to provide notice to its customers of the program's ending. This notice should include information about other demand response programs and aggregator contracts for which the customer may be eligible. PG&E should work directly with affected customers to help them understand their options to continue in other programs or contracts with aggregators.

The Bridge Funding Decision A.08-12-038 authorized funding of $4,623,996 for the BEC in 2009; this previously approved budget should be more than sufficient to operate the program until its discontinuation before the end of 2009.

11.2. SCE

11.2.1. Summer Discount Plan

SCE's Summer Discount Plan is an emergency-triggered program formerly called the Air Conditioning Cycling Program, which is similar to PG&E's SmartAC program (discussed above) and SDG&E's Summer Saver Program (discussed below). Under this program, SCE installs radio-controlled switches in participants' central air conditioners, allowing SCE to interrupt the customer's air conditioning to drop load during times of peak electricity demand. As an incentive, participants receive credits on their summer electricity bills. In recent years, the Summer Discount Program has had a load impact of approximately

500 megawatts. SCE forecasts a budget of close to $41 million, excluding customer incentives, which are funded through the SCE General Rate Case, and proposes maintaining the program while transitioning the program to take advantage of Programmable Communicating Thermostats utilizing the two-way communications capabilities of the SCE advanced metering infrastructure system, SmartConnect. After this transition, the Summer Discount Program would utilize price responsive triggers for cycling, rather than the current emergency triggers utilizing one-way radio switches. SCE also requests some growth in this program between 2009 and 2011, with the addition of approximately 4 megawatts per year. The estimated cost effectiveness of this program is 1.03, meaning it may be marginally cost effective. Party positions on the Summer Discount Program largely reflect parties' positions on emergency-triggered programs in general.

11.2.1.1. Discussion

Consistent with our treatment of other emergency-triggered demand response activities considered in these applications, we do not envision expanding the Summer Discount Program at this time, pending the outcome of Phase 3 of the Demand Response OIR. For this reason, we do not increase funding, nor do we to approve a market and outreach budget of over $3 million per year, as requested by SCE. In addition, the apparently marginal cost effectiveness of this program does not argue for expansion, and may be improved if SCE is able to maintain enrollment in the program with a decreased budget for marketing. We support SCE's efforts to transition this program to use more price-responsive triggers, and hope to see a progress in that transition over the next several years. We adopt total funding for this program of $9,778,000 per year, the amount requested for 2009 less the requested marketing and outreach;

in order to maintain the program at its current size, we will approve a reduced marketing budget of $1 million to allow SCE to compensate for attrition in the program. This results in total funding for the Summer Discount Program from 2009-2011 of $30,334,000.

11.2.2. Agricultural Pumping – Interruptible

The Agricultural Pumping – Interruptible (AP-I) program is another emergency-triggered program specific to SCE. Through the AP-I program, SCE offers monthly energy credits for eligible agricultural pumping customers who allow the utility to interrupt their load during CAISO or local emergencies. The program has existed since the 1970s. It was closed to new enrollments in 1998 and reopened in 2001. In D.06-03-024, SCE was authorized to expand the marketing of the program during the 2006-2008 period. SCE proposes to further expand marketing of the program in 2009-2011; the utility estimates 57 megawatts of potential load reductions for this program by the end of 2011. SCE requests a total of $1,529,464 million for AP-I.[81] Like the Summer Discount Program, the estimated benefit to cost ratio is 1.03. Party positions on the AP-I program reflect their general positions on emergency-triggered programs.

11.2.2.1. Discussion

Consistent with treatment of other emergency-triggered demand response programs in this proceeding, we freeze the size and budget of the program for 2009-2011, pending a decision on the optimal load needed from emergency-triggered programs. In addition, as in the case of the Summer Discount Program, we exclude some of the requested marketing costs from this program's

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[81] SCE Amended Testimony, Volume 1, pp. 31-32.

budget to discourage the expansion of this program. We approve annual costs of $466,000 for 2009 through 2011; this equals the average SCE funding request for 2009-2011, excluding. We adopt total funding for this program of $1.4 million for 2009-2011.

11.2.3. Rotating Outage Program

SCE's Rotating Outage Program generally supports communications to customers about policies and procedures related to rotating outages during declared electric emergency situations. SCE explains that the program has continued in "active maintenance mode," and proposes no changes for the 2009-2011 period. The utility forecasts expenditures of $408,738 for 2009-2011 for labor and communications.[82]

The communications supported by the Rotating Outage Program include both Commission-mandated notices and courtesy notifications intended to facilitate the administration of emergency rotating outages. No parties object to the continuation of these activities at the requested funding level, and we approve funding of $408,738 to support this program during 2009-2011.

11.2.4. Agricultural Pump Timer Program

SCE's Agricultural Pump Timer Program utilizes Time Management Load Control devices to allow customers to interrupt their equipment at peak times, in order to take advantage of low off-peak utility rates. Customers enrolling in this program pay for the initial installation of timer equipment, and any savings realized by customers are captured through lower utility bills due to enrollment in a tariff that rewards shifting of pumping away from higher-priced peak

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[82] SCE Exhibit 1, p. 43.

electricity hours. SCE requests $42,000 per year for this program over the 2009-2011 period, for a total budget of $126,019; this covers communications and general administration of the Agricultural Pump Timer Program only. Initial equipment costs under the program are paid by customers, and replacement equipment, when needed, is paid for out of general rate case funds. No parties object to the continuation of these activities at the requested funding level, and we approve funding of $126,019 to support this program during 2009-2011.

11.2.5. Energy Options Program

Energy Options is a new program SCE proposes to combine and replace its Capacity Bidding Program and Demand Bidding Program beginning in 2010. SCE's Energy Options Program would allow customers to choose among six existing Capacity Bidding Program options and an option similar to the Demand Bidding Program. The demand bidding option would utilize monthly load nominations rather than daily bids, and incentives would be calculated as they are currently, based on actual load drop.[83] Energy Options would allow customers to switch among different options each month to allow customers to tailor their demand response commitments to meet their individual needs. Additionally, SCE intends the products to be scalable so that customers under 200 kilowatts who receive an Edison SmartConnect meter can also participate.

SCE expects minimal losses of Capacity Bidding Program and Demand Bidding Program customers during the transition to Energy Options, and expects an increase in the number of customers enrolled in Capacity Bidding products. SCE proposes that aggregators be able to participate in Energy Options

[83] SCE Exhibit 1, p. 21.

and receive 100% of the capacity payment for Capacity Bidding Program type options, whereas directly enrolled customers would receive 80% capacity payment for Capacity Bidding Program options, as is currently the case in the capacity bidding program. The utility requests $5,703,864 for program development, administration, evaluation, measurement, and verification, information technology costs, marketing and meters.[84] The estimated benefit to cost ratio for this program is not reported.

11.2.5.1. Other Party Positions

DRA supports the SCE proposal to transition Capacity Bidding Program and Demand Bidding Program into a new Energy Options Program starting in 2010. No party objects to this proposal.

11.2.5.2. Discussion

SCE's Energy Options Program is likely to prove complex to analyze, and it is not clear whether the resulting program will be cost effective. As discussed above, the underlying programs (Capacity Bidding Program and Demand Bidding Program) do not appear to be cost effective in their current form. The availability of a program that offers more flexibility to customers may be more acceptable to customers and may both increase enrollment in demand response activities and make the program more cost effective. We approve the creation of this program and fund it at the requested level for the 2009-2011 period.

SCE's suggestion that aggregators be allowed to participate in the Energy Options program may increase participation in this program and the amount of demand response available at peak times. We approve this request. To ensure

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[84] SCE Exhibit 1, p. 23.

that we are able to evaluate and compare the different participation options available under this program, we require SCE to continue to report each type of notification (day ahead and day of) separately in its monthly report, as well as in its load impact and cost effectiveness analyses. Like other programs utilizing baselines approved in this proceeding, the Energy Options program will use the baseline described in Section 17, below.

11.3. SDG&E

11.3.1. Critical Peak Pricing -- Emergency

SDG&E's Emergency Critical Peak Pricing program (CPP-E) is a voluntary program in which participants may be called on 30 minutes' notice when an immediate load reduction is necessary. SDG&E's CPP-E program is structured similarly to the price-responsive Critical Peak Pricing Tariffs of the three utilities, with higher rates during called event hours in return for lower rates during non-event hours. CPP-E events are called primarily when there is a statewide Stage 1 or 2 system emergency or a local system emergency. CPP-E events may be as much as six hours long on a particular day and may not exceed 80 event hours per year or 40 hours per month. SDG&E does not propose changes to this program. SDG&E requests a budget of $328,541 for CPP-E in 2009-2011, and the estimated TRC benefit to cost ratio is 2.8. SDG&E estimates the load reduction potential for this program at 2 megawatts. No parties object to the continuation of this program.

It is reasonable to continue this program pending the Commission's decision in Phase 3 of R.07-01-041 on the overall level of emergency-triggered demand response needed in the state and the potential need for changes to those programs. We approve SDG&E's request to continue the CPP-E program with total funding of $328,541.

11.3.2. Summer Saver

SDG&E's Summer Saver Program (formerly its Air Conditioner Cycling Program) is a voluntary direct load control air conditioner cycling program available to residential, small business and other customers with central air conditioners. As a direct load control program, participants' air conditioning equipment is automatically controlled when necessary to reduce high electricity usage. Like the CPP-E program, SDG&E's Summer Saver may be triggered in a statewide Stage 1 or 2 system emergency or a local system emergency. Summer Saver is currently administered through a third-party aggregator under a contract approved by this Commission, and has a target load reduction of 42.2 megawatts. The estimated TRC benefit to cost ratio for residential customers enrolled in this program is 1.14, and for commercial customers the estimated ratio is 1.48; these results imply that the program may be cost effective in its current form. SDG&E does not request program changes or funding for SmartRate in this application. SDG&E asserts that sufficient funding for the program to operate in 2009-2011 has already been authorized. We authorize the continuation of SDG&E's summer saver program, as requested. In addition, we encourage SDG&E to explore ways to begin transitioning this air conditioner cycling program to use more price responsive triggers.

11.3.3. Peak Day Credit Program

SDG&E seeks to eliminate its existing Peak Day Credit Program, which offers customers a bill credit ranging between 10% and 20% for load reduction during events called under the program. D.08-12-029 approved a budget of approximately $300,000 for this program in 2009. SDG&E asserts that, like its Demand Bidding Program, the Peak Day Credit Program is no longer needed. No parties object to the elimination of this program. Given the relatively small size of the Peak Day Credit Program and the availability of other options for customer enrollment in demand response activities, we approve SDG&E's request to discontinue this program within 30 days of this decision. SDG&E will provide enrolled customers with reasonable notice of the program's discontinuation and information on other demand response activity options.

11.4. Miscellaneous Supportive Activities

All three utilities propose additional demand response-related activities. PG&E requests a total of $29,483,000 for an InterAct/Demand Response Forecasting Tool, Demand Response On-Line Enrollment, a Legacy Demand Response Conversion, a Marketing Decision Support System upgrade, and Interval Meters; SCE requests $13,258,420 for a Demand Response Forecasting System, a Demand Response Resource Portal, and Demand Response System Infrastructure; and SDG&E requests $600,000 for development of Demand Response Codes and Standards.

Several of these items, including PG&E's Legacy Demand Response Conversion, a Marketing Decision Support System upgrade, and Interval Meters and SDG&E's Codes and Standards are not sufficiently supported by information in the utilities' applications, and may be duplicative of activities already funded in these utilities' AMI, energy efficiency or other proceedings. We do not approve additional funding for these efforts, which are not justified by supportive information in the applications. We approve the following selected projects supportive of demand response at the requested budgets:

	2008-2009 Requested Budget	2008-2009 Authorized Budget

PG&E InterAct/Demand Response Forecasting Tool	$10,413,000	$10,413,000
PG&E Demand Response On-Line Enrollment	$ 6,489,000	$ 6,489,000
SCE Demand Response Forecasting System	$ 1,102,453	$ 1,102,453
SCE Demand Response Resource Portal	$ 2,535,000	$ 2,535,000
SCE Demand Response System Infrastructure	$ 9,520,967	$ 9,520,967

12. Enabling Technologies, Automated Demand Response, and Related Activities

Several utility programs support demand response through the development, application, and funding of services or technologies that make demand response easier for program participants. Such services may include audits of demand response or energy saving potential, recommendation of appropriate processes and technologies to facilitate demand response, and funding of process improvements and equipment upgrades. The three main utility activities in this area are the Technical Assistance and Technology Incentives programs, the Emerging Market and Technology Projects, and automated demand response programs and services. These activities, and some related activities conducted by single utilities, are described in this section.

12.1. Technical Assistance and Technology Incentives Programs

The Technical Assistance and Technology Incentives Programs were first authorized in D.05-01-056. The Technical Assistance and Technology Incentives programs of the three utilities differ somewhat in participation requirements, incentive payments, and other structural aspects, but all support the installation of technologies to facilitate customer peak load reduction and demand response. In general, these programs provide large commercial customers with site assessments and technical audits to determine demand response potential, followed by rebates or incentives for the installation of recommended enabling technology to support demand response or related activities such as thermal energy storage or permanent load shifting.

12.1.1. Utility Technical Assistance and Technology Incentives Proposals

12.1.1.1. SCE

For 2009-2011, SCE proposes to continue to integrate demand response and other demand-side management audits by incorporating both demand response and energy efficiency recommendations into its audits. SCE currently requires customers receiving Technical Assistance and Technology Incentives services to be enrolled in a qualifying demand response program at the time of participation. SCE's program provides incentives upon installation of technology by the customer. SCE proposes that in 2009-2011, customers that receive an incentive payment under Technical Assistance and Technology Incentives should be required to enter a bi-lateral participation schedule agreement with SCE to ensure the customer uses the technology in accordance with their stated intent for participating in the program. Based on SCE's proposal, such an agreement would require those receiving large payments under this program to participate in a qualifying demand response program, with a financial penalty if the customer does not perform under that program. SCE requests $50,262,525 including incentives for this program.[85]

12.1.1.2. PG&E Proposals

PG&E has a description of its Technical Assistance Program, and a separate description of its Technology Incentives Program. Through its demand

[85] Exhibit 201, p. 54.

response Technical Assistance program, PG&E offers customers free audits of their facilities. During 2009-2011, PG&E proposes to integrate the Technical Assistance program with its Integrated Energy Audits Program, funded through its energy efficiency budget. Through the resulting combined program, PG&E proposes to conduct detailed energy audits that will include consideration of energy efficiency, demand response, and Distributed Generation options. In addition, PG&E proposes creating an enhanced web-based audit tool, called the Universal Energy Audit Tool, to allow customers to generate reports that include specific information on the costs and benefits of energy efficiency, energy conservation, demand response, and distributed generation, customized for their particular circumstances. PG&E requests a total of $2.9 million for the demand response activities associated with the Technical Assistance portion of its Integrated Energy Audits program.

Similar to its plan for Technical Assistance, PG&E proposes to integrate its Technology Incentives program with its energy efficiency incentives, to better coordinate these activities and make the incentive programs more convenient. PG&E intends to evaluate all Technology Incentives projects for Auto demand response potential. PG&E also proposes expanding its Technology Incentives program to new construction projects in 2009-2011; in 2006-2008, this program only funded projects to retrofit existing construction. PG&E's program provides incentives of 50% of the cost of technical incentives project with a maximum rebate of $125 per kilowatt of expected demand response.[86] PG&E proposes to require customers receiving Technology Incentives rebates of more than $50 per

[86] PG&E requests authority to unilaterally lower the percentage it pays in order to serve more customers with the same funding.

kilowatt to participate for at least three years in PeakChoice options with committed load reduction, Critical Peak Pricing, the Capacity Bidding Program, the Base Interruptible Program, or a program under PG&E's aggregator managed portfolio. Customers receiving a rebate of less than $50 per kilowatt could participate in its Demand Bidding Program or a PeakChoice "best efforts" option. PG&E also requests authority to lower the maximum incentive it pays for retrofit projects from the current level of $250 per kilowatt to $125 per kilowatt, and to offer the same $125 per kilowatt incentive to new construction projects. PG&E requests a total budget of $10.3 million for the Technical Incentives program for 2009-2011. About $3 million is requested for new construction projects, with the remaining $7.3 million for retrofit projects.

12.1.1.3. SDG&E Proposals

Like PG&E, SDG&E separates the descriptions of its Technical Assistance Program and its Technology Incentives programs. SDG&E's Technical Assistance program provides audits to help customers participate in demand response activities and reduce energy costs. Customers with a demand of 20 kilowatts or greater are eligible for the program and receive an incentive to offset the cost of the audit.[87] Like PG&E, in 2009-2011 SDG&E proposes offering customers a fully integrated audit service that will include energy efficiency and demand response.[88] SDG&E requests $10 million for its Technical Assistance program during 2009-2011.[89]

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[87] Exhibit 103B, Appendix B Program Concept Papers, p. 54.

[88] Exhibit 103B, Appendix B Program Concept Papers, p. 58.

[89] Exhibit 103B, Appendix B Program Concept Papers, p. 56.

SDG&E's Technology Incentive program provides an incentive that offsets the cost of purchase and installation of demand response measures. Non-residential customers with an energy demand greater than 20 kilowatts are eligible to participate in the program. SDG&E proposes an incentive level of $100 per kilowatt for non-automated demand response technologies customers receiving 60% of their incentive after completing a load shed test, and the remaining 40% only if they enroll in a demand response program with a one-year commitment.[90] SDG&E proposes a higher per-kilowatt rebate for installation of automated demand response technologies; this is discussed along with auto demand response proposals, below. The utility proposes funding of approximately $12,762,841 for the 2009-2011 time period; this includes the utility's requested budget for automated demand response.

12.1.2. Other Party Positions

TURN recommends cuts to the proposed Technical Assistance and Technology Incentives budgets for all three utilities. TURN suggests a Technical Assistance and Technology Incentives budget for SCE of $15.159 million, $35.113 million less than the SCE proposal.[91] TURN argues that SCE's requested funding is inflated relative to its recorded costs, and contends that the administrative costs are high compared to the incentives paid under the program. Specifically, TURN asserts that SCE spent $5.885 million on Technical

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[90] Exhibit 103B, Appendix B Program Concept Papers, p. 61.

[91] TURN Opening Brief, pp. 7 & 8: This revision is based first on prorating SCE's costs for 2008, which TURN projects to be $2.85 million. TURN then increased this figure by 60% to account for increased customer participation and administration costs. Finally that figure was increased by 5% per year to reach TURN's proposed total of $15.159 million

Assistance and Technology Incentives in 2007, of which TURN asserts that only $1.043 million went towards incentives compared to $4.842 million on program administration. TURN further notes that SCE projected to spend $12.824 million on incentives and $2.195 million on administration in 2008, but notes that as of its September 2008 report, SCE had only recorded $2.451 million in total costs for that year total.[92] SCE responds to this assertion by noting that not all funds committed under this program in 2008 were actually paid within that year, and that the amounts committed are being paid over time.

TURN counters that SCE should have a line in its monthly report for total commitments, so that committed funds are not recorded as "unspent" on SCE reports. Additionally, TURN argues that SCE's recent monthly reports do not reflect a dramatic change in recorded costs, which one might expect would occur consistent with SCE's claim that it has an additional $12.1 million committed through this program in addition to the amounts already paid.

TURN objects to PG&E's high administration costs for the Technical Assistance and Technology Incentives programs, and recommends that the Commission reduce the combined budget for these programs by $2.22 million.[93] In its reply brief, PG&E responds that its Technology Incentives proposal includes services such as technical consulting, design, and verification, which are not appropriately classified as administrative costs, and making the administrative costs appear high relative to incentives.

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[92] TURN Opening Brief, p. 77.

[93] TURN Opening Brief, pp. 74-75.

TURN also objects to PG&E's request for authority to unilaterally change the 50% customer contribution to qualify for a 50% payment for new construction under Technology Incentives.[94] TURN asserts that the current requirement is consistent with existing Line Extension rules applicable to new construction. TURN suggests that a decision on this proposal should be made in the context of a review of the utilities' rules for connecting new residential and non-residential customers (Rules 15 and 16 Electric Line and Service Extension rules), rather than in this proceeding, to ensure that all parties and the Commission understand the ramifications of the proposed changes.

With reference to SDG&E's Technical Assistance and Technology Incentives request, TURN notes that in SDG&E's AMI application approved in D.07-04-043, SDG&E claimed that AMI deployment would enable the company to reduce or eliminate the Technical Assistance and Technology Incentives funding and services, beginning in 2009. TURN highlights the fact that SDG&E's proposed budget is 97% of the authorized budget for 2006-2008, which does not appear to be a significant reduction.[95] TURN further recommends that if the Commission decides to approve any SDG&E Technical Assistance and Technology Incentives funding, that the proposed budget should be adjusted downward to reflect recorded expenditures for 2006-2008.

DRA comments only on the SDG&E Technical Assistance and Technology Incentives proposal, and not on those of SCE or PG&E. DRA objects to SDG&E's treatment of its Technical Assistance and Technology Incentives activities as a

[94] TURN Opening Brief, pp. 75-76.

[95] TURN Opening Brief, pp. 79-80.

stand-alone program for reporting and analysis. DRA argues that, like the other utilities, participants in SDG&E's Technical Assistance and Technology Incentives programs should be categorized and their load impacts analyzed according to the Demand Response program in which they ultimately enroll after receiving program services. To accomplish this, DRA recommends that SDG&E change several aspects of its program, specifically its reporting, analysis, and cost allocation, to be more consistent with the other utilities' treatment of their comparable programs.

12.1.3. Discussion

Technical Assistance and Technology Incentives activities facilitate peak load reduction and demand response by utility customers, and in many cases lead directly to customer enrollment in utility demand response programs. By increasing the effectiveness of other demand response programs, and supporting demand side management in general, Technical Assistance and Technology Incentives support is consistent with state policy goals including reduction of peak electricity demand and promoting energy efficiency.

As SCE notes, TURN objects to SCE's proposed budget for Technical Assistance and Technology Incentives but does not object to the objectives; or costs related to benefits of the program.[96] In fact, no party argues against retention of Technical Assistance and Technology Incentives activities; TURN and DRA raise questions about the appropriate funding levels and specific program design issues. It is reasonable for Technical Assistance and Technology

[96] SCE Exhibit 7, p. 44.

Incentives activities to be available to customers statewide, and we will retain this program for all three utilities.

TURN argues in part that the utilities' administrative costs for this program are too high compared to the program incentives. While it is desirable in general for the administrative costs of a demand response program to be less than the program's incentives. This principle is not applicable to Technical Assistance and Technology Incentives activities, which include many activities that do not result in the payment of financial incentives. These services, such as conducting audits, developing company-specific demand response plans, and recommending equipment and strategies to improve load reduction, are not true program administration activities (such as data collection or processing), and should not be considered program administration in the determination of program budgets. As a result, it would not be appropriate to limit the budget for such services to twice the financial incentives paid to customers.

TURN objects to the SCE budget request on the additional grounds that SCE's application and program reports show spending for 2006-2008 well below the level requested for 2009-2011. SCE notes that the application and reports cited by TURN do not show money that has been committed under the program, which allows customers to "reserve" funds for up to 18 months while they make recommended improvements and upgrades to facilitate demand response. When the improvements are made, SCE pays the "reserved" money to the customer in the form of a rebate. In addition, SCE notes that the spending data provided for all three utilities in their applications is not current.

SCE's method of reporting money spent under its Technical Assistance and Technology Incentives program makes it difficult to determine the demand for this program or the budget required to sustain it through 2011. To address this, we require SCE to add a line to all future reports on this program to show the funds committed under this program in a given month and year. This will make it possible to develop better budget forecasts for future funding cycles.

TURN further objects to SDG&E's request for Technical Assistance and Technology Incentives because in the company's AMI application in A.05-03-015, SDG&E estimated that it would be able to reduce budgets for these programs after AMI deployment, with decreases in funding starting in 2009. TURN argues that, because SDG&E's business case included approximately $110 million in benefits for the reduction or elimination of Technical Assistance/Technology Incentives costs, and the Commission in adopting SDG&E's business case agreed that AMI would lead to a reduction in funding for this category, SDG&E should not receive funding for continuing its Technical Assistance and Technology Incentives program. In its comments on the proposed decision, TURN asserts that funding Technical Assistance and Technology Incentives modifies the Decision in SDG&E's AMI case without proper notification of parties.

SDG&E has not yet fully deployed its Advanced Metering Infrastructure system, and will not complete deployment for several years. It is not reasonable to expect that SDG&E would be able to immediately eliminate demand response programs based on the approval (not implementation) of its AMI system. In addition, as discussed elsewhere in this decision, forecasts based on assumptions of future activities are estimates, and may be subject to some change. For these reasons, we do not reduce the utility's proposed budgets in conformance with estimates the company provided in that earlier proceeding. By 2012, SDG&E will have completed deployment of its AMI system, and we expect SDG&E will be able to substantiate the claims made in its AMI proceeding by substantially reducing or eliminating Technical Assistance and Technology Incentives costs.

As described above, DRA objects to several aspects of the design and analysis of SDG&E's Technical Assistance and Technology Incentives activities. We share many of DRA's concerns. We adopt the Technical Assistance and Technology Incentives budget requested by SDG&E, but we also require SDG&E to make its activities more consistent with the Technical Assistance and Technology Incentives activities of the other utilities. Specifically, in future reports, SDG&E will no longer consider its Technical Assistance and Technology Incentives activities as a stand-alone program for the purposes of reporting and analysis. SDG&E will classify participants by the demand response program in which they ultimately enroll, and will report load impacts of those customers by the program in which they are enrolled. SDG&E shall work with Energy Division staff to ensure that the Technical Assistance and Technology Incentives sections of its monthly reports are designed appropriately and include sufficient information.

We allow PG&E to extend its Technical Assistance and Technology Incentives activities to new construction, but the company's request for authority to unilaterally change the required customer contribution towards Technical Assistance and Technology Incentives funding for new construction is denied. There is not sufficient information in the record on the desirability of making this change or the possible implications on PG&E's line extension rules.

The Technical Assistance and Technology Incentives activities and participation requirements of the three utilities vary widely; it is not reasonable for customers in different utility service territories to be subject to very different requirements and program rules for similar services. It would be difficult to require completely uniform requirements; the utilities already have outstanding commitments based on their current program designs, and some differences between utility operations may justify some level of variation across the state, as is the case for other demand response programs. Still, to ensure equal treatment and access to customers throughout the state, we require all three utilities to make their programs more consistent in several ways, as follows:

- The maximum rebate or incentive for non-Automated Demand Response services provided through Technical Assistance and Technology Incentives programs will be $125 per kilowatt for all utilities.

- The maximum rebate for automated demand response equipment installed through Technical Assistance and Technology Incentives or Automated Demand Response Programs will be $300 per kilowatt for all utilities.

- Customers receiving an incentive of $100 or more will be required to make a minimum one-year commitment to a demand response program or Critical Peak Pricing tariff.

- SCE and SDG&E will follow PG&E's lead to develop proposals for integrating their Technical Incentives programs with other, similar demand side management incentive or rebate programs; They should submit detailed proposals consistent with ongoing work through the Energy Efficiency Strategic Plan workgroups as part of their next demand response program applications.

These rules will apply to customers receiving services under these programs beginning January 1, 2010. We approve the following budgets for the utilities' Technical Assistance and Technology Incentives Activities:

	2009-2011 Requested Budget	2009-2011 Authorized Budget
PG&E Technical Assistance	$2,942,000	$2,942,000
PG&E Technology	$10,310,000	$10,310,000

Incentives		
SDG&E Technical Assistance	$10,011,326	$10,011,326
SDG&E Technology Incentives	$12,662,841	$12,662,841
SCE Technical Assistance and Technology Incentives	$50,262,525	$50,262,525

Because the Technical Assistance and Technology Incentives activities will interact with other demand-side management programs, and are likely to be affected by further developments in Commission proceedings related to Energy Efficiency in particular, we encourage the utilities to coordinate the activities in this category with other approved demand side management activities.

12.2. Emerging Markets and Technologies

The Emerging Markets and Technologies Programs fund research projects for technologies and equipment, processes, and products. Currently, there are no statewide standards that specify what types of technologies or projects are appropriate for funding through Emerging Markets and Technologies, but past projects have included research into energy storage technologies, the potential of AMI systems to influence demand response, and coordination between demand response and energy efficiency.

12.2.1. Utility Emerging Markets and Technologies Proposals

12.2.1.1. SCE Proposal

SCE notes that during 2006-2008, it funded three main types of projects through Emerging Markets and Technologies: development of technologies, codes and standards, and innovative technologies. SCE requests a budget of $9,244,405 for Emerging Markets and Technology for 2009-2011. Proposed projects include energy storage projects, integrated demand side management activities, and projects to expand demand response to residential customers. In addition, SCE describes projects that would integrate with its AMI system, such as development of customer interfaces and displays, intelligent circuit breakers, smart appliances and communication tools for pool pump cycling.[97] SCE also notes that research is done in collaboration with other institutions and agencies in order to facilitate identification of new technologies and participation in research and experiments. Additionally, SCE requests that funding for a given project be allowed to continue for 48 months after the initiation of a project, and not be limited to the 2009-2011 period.[98]

12.2.1.2. PG&E Proposal

PG&E's Emerging Markets and Technology program focuses on research and development into improving processes, developing resources, and increasing the attractiveness of demand response technology. PG&E provides a general description of its contemplated activities in the 2009-2011 period, stating that it intends to emphasize projects which integrate energy efficiency and demand response, and, like SCE, plans to continue to work with the Demand Response Research Center and other research organizations. Specific areas of focus mentioned by PG&E for 2009-2011 include: energy storage, smart thermostats and smart appliances, technologies compatible with AMI, advanced lighting systems and energy management systems. PG&E forecasts $2,421,000 for this program in the 2009-2011 cycle.

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[97] SCE Exhibit 1, pp. 97-100.

[98] SCE Exhibit 1, p. 100.

12.2.1.3. SDG&E Proposal

SDG&E's Emerging Technologies program was previously called the Emerging Markets Program. The program evaluates and develops technologies to be installed at customer sites to maximize demand response potential. The program also provides technical support related to statewide codes and standards for demand response. In 2009-2011, SDG&E proposes to pursue technologies that emphasize demand response, energy efficiency, and renewables. SDG&E proposes $2,142,495 for this program in 2009-2011.

12.2.2. Party Positions on Emerging Markets and Technology Funding

TURN objects to the funding requests of both SCE and SDG&E. TURN notes that both of these utilities intend to use Emerging Markets and Technology funding at least in part for projects that will utilize or integrate with the utility's AMI system.[99] As in its discussion of Technical Assistance and Technology Incentives, TURN argues that the Commission should not fund AMI efforts beyond what was already adopted in the utility's AMI budget.[100] TURN recommends that the Commission deny all requested funding for SDG&E's Emerging Markets and Technology projects because of their connection to SDG&E's AMI system. As an alternative, TURN proposes that if the Commission does not reject SDG&E's program, it should reduce funding to the level spent in 2006-2008. Similarly, TURN recommends that the Commission authorize no more than SCE's 2008 spending level annually for Emerging

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[99] TURN Opening Brief, p. 54.

[100] TURN Opening Brief, p. 36.

Markets and Technology projects in 2009-2011. SCE spent $1,818,879 in 2008, which TURN argues would support a three-year budget of $5,456,637.

12.2.3. Discussion

Given the rapid evolution in demand response techniques, enabling technologies, and evaluation methods, and the desirability of increasing the availability of cost effective demand response, there is a clear benefit to investing in research and development that will encourage the adoption and growth of demand response. It is reasonable to continue funding Emerging Markets and Technology projects for all three utilities. As discussed elsewhere in this decision, we support activities that will leverage the utilities' AMI investments to increase demand response. For these reasons, we do not adopt TURN's proposal to discontinue funding for Emerging Markets and Technology.

Similarly, while the utilities, particularly SCE, took several years to ramp up their Emerging Markets and Technology activities to current funding levels, the expansion of availability of and participation in demand response programs and dynamic pricing tariffs support the utility requests for maintaining or increasing budget in this area for 2009-2011. For this reason, we approve the requested utility budgets for Emerging Markets and Technology.

At the same time, it is important to ensure that the research and development undertaken is understood by this Commission and can be shared with other research entities. We require SCE, SDG&E, and PG&E to provide annual reports on their Emerging Markets and Technology projects to the Commission's Energy Division. These reports shall summarize the projects the utility is supporting with Emerging Markets and Technology funds, including the potential benefits of the technology or technique, the types of activities undertaken as part of the project, and any results that are available. The utilities will work with Energy Division staff to develop a reporting format, and will provide reports on the previous year's Emerging Markets and Technology activities to the Director of the Energy Division by March 31 of each year.

We decline to approve SCE's proposal that specific projects retain their funding for 48 months after they are initiated. We recognize that some projects might continue for several years, and that it may be appropriate for particular projects to go beyond the end of the 2011. Rather than giving blanket approval for unidentified long-term projects, we require utilities to include discussions of the expected term of each project in the project annual reports. Utilities also may either file a Tier 2 advice letter to request funding from within their existing budget for specific projects that need to go beyond the end of 2011, or may include a request to continue these projects in their next demand response funding application.

It may be helpful to develop guidance on the use of demand response-related research and development funds. Such guidance could define the types of projects that are appropriately funded under the Emerging Markets and Technology program and reasonable ranges for future funding, as well as helping to ensure that utilities do not duplicate one another's projects. We intend to develop such guidance before the next set of demand response portfolio applications are filed for a future budget cycle.

	2009-2011 Requested Budget	2009-2011 Authorized Budget
PG&E Emerging Markets and Technology	$2,421,000	$2,421,000
SDG&E Emerging Markets and Technology	$2,142,495	$2,142,495
SCE Emerging Markets and Technology	$9,244,405	$9,244,405

12.3. Automated Demand Response

Automated demand response, also known as "auto demand response," "auto DR" or "auto demand response," refers to automated enabling technologies that allow a customer's equipment or facilities to reduce electricity usage automatically in response to peak load conditions or high prices without the customer needing to take a specific action. In D.06-11-049, the Commission directed the utilities to establish pilots for automated demand response, and all three utilities propose maintaining or expanding their automated demand response activities in 2009-2011.

12.3.1. SCE Proposal

For 2006-2008, the Commission authorized SCE to conduct an automated demand response pilot with a budget of $1,790,000. SCE's program was expected to generate as much as 10 MW of load reduction from more than 20 large commercial customers enrolled in either the Demand Bidding Program or a Critical Peak Pricing tariff.[101]

SCE suggests that its automated demand response program is now starting to generate customer interest.[102] SCE proposes transitioning its existing pilot into a broader program in order to accommodate more participants in 2009-2011. Along with this change, the utility proposes enhancing customer outreach and changing some aspects of program implementation, for example by allowing automated demand response customers to participate in the Energy Options Program when it replaces the Demand Bidding Program in 2010.[103] SCE

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[101] SCE Exhibit 1, p. 60.

[102] SCE Exhibit 1, p. 62.

[103] SCE Exhibit 1.

estimates that these program enhancements will result in an additional 30-35 megawatts in estimated load reduction by the end of 2011.[104] SCE requests $4,302,881 for this proposed automated demand response program in 2009-2011.[105]

12.3.2. PG&E Proposal

PG&E conducted automated demand response programs in 2006-2008 that were expected to generate about 30 megawatts in estimated load reduction by end of 2008 through participants' enrollment in Critical Peak Pricing and the Demand Bidding Program.[106] PG&E proposes to expand the Automated Demand Response program, make certain enhancements, and offer more demand response program enrollment choices (ABEC, Capacity Bidding Program, and PeakChoice) to customers implementing the automated demand response program.[107] PG&E requests a budget of $16,117,000, with an estimated demand response capability of 45 megawatts by the end of the 2009-2011 cycle.[108]

12.3.3. SDG&E Proposal

SDG&E's existing automated demand response pilot offers customers a rebate of the lesser of the cost of automated demand response equipment and installation or $300 per kilowatt. SDG&E administers these rebates through its Technical Incentives program, described above. Unlike PG&E and SCE, SDG&E did not report any estimated load reduction associated with this program to

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[104] SCE Exhibit 1.

[105] SCE Exhibit 1, p. 63.

[106] PG&E Exhibit 201, Chapter 2, p. 36.

[107] PG&E Exhibit 201, Chapter 2, p. 39.

[108] PG&E Exhibit 201, Chapter 2, p. 39.

date, nor did it provide any estimated load reduction for the 2009-2011 cycle. SDG&E suggests that because its automated demand response program is "just beginning to produce results [in 2008], SDG&E does not believe further modifications are warranted at this time." Based on this assessment, SDG&E does not propose any specific augmentations to its Automated demand response program other than a slight modification to the incentive payment.[109]

12.3.4. Discussion

No parties objected to the automated demand response requests of the utilities. The automated demand response program appears to result in some load reduction, through participant enrollment in other demand response programs. The utilities have not submitted any analysis of whether automated demand response programs are cost effective on their own, separate from the underlying programs in which participants ultimately enroll. Nor have they provided data on actual past performance of Automated Demand Response customers or data to indicate the portion of load reduction attributable to Automated Demand Response on an individual program basis. As a result, it is not clear whether similar load reductions could have been achieved if participants had enrolled directly in the underlying demand response program without first receiving services and rebates through automated demand response. Without knowing whether these programs are cost effective, it is difficult to evaluate the reasonableness of the utilities' proposals the funding and growth targets set by all three utilities.

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[109] SDG&E Exhibit 102A, p. 54.

So, we expect that a formal analysis of Auto DR program may likely yield positive results and believe that continuing these programs is reasonable and in the public interest. Rather than discontinuing these promising activities because insufficient information is available on their results at this time, we adopt the activity and funding proposals of the utilities and require them to collect detailed information on Auto DR programs in order to facilitate a complete analysis of these programs results, including cost effectiveness, comparison of load reduction performance by customers with and without Auto DR, and comparison of predictability and reliability of load reduction by customers with and without Auto DR, and an evaluation of the effectiveness of Auto DR in enabling further expansion and improvement of demand response programs in line with Commission's goals for demand response and the integration of demand response into CAISO markets. The Demand Response Measurement and Evaluation Committee (DRMEC) will oversee these evaluations. Utilities will report these results by September 30, 2010, to the Energy Division Director, along with reports on their Emerging Markets and Technology projects.

We direct the utilities to (1) jointly hold a public workshop to present and discuss their findings and solicit feedback from the parties and (2) jointly hold a second public workshop to present proposals based on the results of the first workshop and solicit feedback and other proposals from the parties. The timing of these workshops shall be coordinated with other workshops planned by the DRMEC. Future Auto DR proposals should leverage applicable Auto DR-related open standards emerging from the federal Smart Grid standards development activities. The utilities are directed to include proposals based on the workshop findings for funding and incorporating Auto DR into demand response programs in their applications in the Demand Response proceeding for the next

2012-2014 cycle. In the interim, in recognition of expected rollout of default dynamic prices for large C&I customers offering a potential opportunity to leverage Auto DR to ease the transition for some customers, we direct the utilities to consider allocating funds within the appropriate authorized budgets (in this or other proceedings) toward education of customers about Auto DR option and encourage implementation of Auto DR by customers being defaulted to dynamic prices.

	2009-2011 Requested Budget	2009-2011 Authorized Budget
PG&E Automated Demand Response	$16,117,000	$16,117,000
SDG&E Automated Demand Response	(included with Technical Assistance and Technology Incentives)	
SCE Automated Demand Response	$4,302,881	$4,302,881

13. Marketing, Education, and Outreach

California has one statewide education and awareness program focused on demand response, which is called Flex Alert or the Statewide Demand Response Awareness Campaign (formerly referred to as Flex Your Power Now). Through the use of mass media such as TV commercials, radio advertisements, billboards, newspapers, and other communication avenues, Flex Alert is intended to educate the general public about the need to reduce electricity during times of peak electricity demand.

PG&E proposes to continue its Flex Alert program in 2009-2011, and requests a total of $6,405,000 for this campaign. SCE forecasts expenditures under this program of $4,947,991for 2009-2011, and SDG&E requests a total of $1,250,000 for its Flex Alert campaign.

TURN asserts that it is irrational to spend money educating customers and conducting marketing for programs when those programs may change dramatically once demand response can be bid into the CAISO's new markets as Proxy Demand Resource or Participating Load. TURN recommends the utilities focus on the transition into the CAISO's new markets instead of on marketing existing demand response activities.[110]

SF Power objects to several elements of PG&E's marketing, education, and outreach funding requests. SF Power suggests that "funding associated with demand-response marketing, education, and outreach should be limited to supporting broadcast alerts during specific periods in which electricity demand is straining the grid."[111] SF Power also recommends that the utilities should pay financial incentives to nonprofits and other third parties to enroll participants in demand response programs. The Commission has endorsed outreach by community based organizations (CBOs) in other areas of demand side management (notably, in outreach for Low Income Energy Efficiency activities, and in workforce training for general energy efficiency), but has not yet adopted a policy on the use of CBO outreach for demand response. We decline to adopt this SF Power recommendation; as PG&E notes, there is insufficient information in the record of this proceeding to support this request. We are open to examining party proposals for expanding CBO and non-profit outreach for demand response in a future proceeding, consistent with our existing policy for energy efficiency activities.

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110 TURN Opening Brief, p. 10.

111 SF Power Opening Brief, pp. 2-3.

It is reasonable to continue the Flex Alert Campaign in its current form at the requested funding levels pending final recommendations of the California Energy Efficiency Strategic Plan on coordination of statewide marketing, education, and outreach efforts. The Strategic Plan required a brand assessment of the closely related, Flex Your Power brand, with pending recommendations that may have an impact on the Flex Alert brand. Therefore it may be appropriate to reevaluate the structure and funding of this program before the end of the 2009-2011 period. We adopt the following budgets for the Flex Alert Program:

	2009-2011 Requested Budget	2009-2011 Authorized Budget
PG&E Flex Alert	$6,405,000	$6,405,000
SDG&E Flex Alert	$1,253,886	$1,253,886
SCE Flex Alert	$4,947,991	$4,947,991

In some cases, the utilities have also requested funding for marketing and outreach as part of the budget of specific programs. In many cases, we authorize some marketing funds as part of program specific budgets in order to maintain enrollment during 2009-2011, but we expect the utilities to move towards more coordinated marketing, education, and outreach, and reduce or eliminate such program-specific budget requests for the 2012-2014 period.

In addition to the statewide Flex Alert Campaign, the utilities request funding for several utility-specific marketing programs, including PG&E's DR Core Marketing and Outreach program, and SCE's Circuit Savers, Agriculture and Water Outreach, Federal Power Reserve Partnership, Energy Leaders Partnership, Income Qualified Customers Outreach Pilot and Integrated Demand-Side Management Marketing. SDG&E proposes a Customer Outreach, Education, and Awareness program, and a Demand Response Emerging

Technologies program. PG&E requests $10,707,000 for its specialized marketing programs, SDG&E requests $6,943,857, and SCE requests $14,329,454 for these programs.[112] TURN objects to the utilities' specialized marketing budgets, arguing that much of the funding requested by PG&E will provide a "slush fund" for activities that do little more than generate public relations benefits for the utilities.[113] TURN reiterates its objection to these programs in its comments on the proposed decision, suggesting that based on historical recorded spending and other factors, funding for the SCE Federal Reserves Partnership should be reduced from $1.65 million to $81,000, and the budget for SCE's Energy Leadership Program budget should be reduced from $2.605 million to $692,000.[114]

These programs should be reviewed in the context of the utilities' energy efficiency application proceedings, in order to facilitate coordination among demand-side management activities. However, despite the increase in budget requests from historical spending levels, the increased budget requests for specialized marketing and education activities appear to be consistent with the expected general expansion of price responsive demand response and dynamic pricing activities. We approve the utilities' requested funding for these programs. We direct the utilities to coordinate these specialized marketing, education, and outreach activities with similar activities conducted with funding from energy efficiency and other demand-side management programs. In

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112 SCE Exhibit 1, pp. 66-84.

113 TURN Opening Brief, p. 2.

114 Opening Comments of the Utility Reform Network on the Proposed Decision of ALJ Hecht, p. 10.

addition, when marketing, education, and outreach funding for demand response programs are being decided, we encourage outreach to underserved communities via non-profit organizations and community-based organizations. We approve the requested budgets, as follows:

	2009-2011 Requested Budget	2009-2011 Authorized Budget
PG&E Core Marketing and Outreach	$10,707,000	$10,707,000
SD&E Customer Education, Awareness, and Outreach	$6,943,854	$6,943,854
SCE Specialized Marketing Programs	$9,381,464	$9,381,464

The activities and budgets for specialized marketing approved here may be reviewed and revised, if appropriate, in A.08-07-021, et al.

14. Proposed Pilot Programs for 2010-2011

In the utilities' were directed to develop and propose pilot programs to explore several possible uses of demand response and permanent load shifting. Some pilot proposals to provide Participating Load under the CAISO's new markets were approved in D.08-12-038 for operation in 2009; the pilots not approved in that decision are addressed here. The utilities may continue the pilots approved in D.08-12-039 during 2010 and 2011 at the already-approved funding levels, as reflected in the adopted budgets in Section 24, below.

14.1. PG&E

In addition to the pilots approve in D.08-12-039 PG&E proposed three pilots for 2009-2011: a Small Customer Load Aggregation Pilot, the Commercial and Industrial (C&I) Base Intermittent Resource Management Pilot, and the Plug-in Hybrid Electric Vehicle/Electric Vehicle (PHEV/EV) Smart Charging Pilot. The objective of the first pilot is to assess the load reduction potential of small customers provided with enabling technologies. The goal of the other two pilots is to understand the Demand Response storage capabilities of different technologies, including thermal energy storage and batteries, in order to provide demand response products that can vary with load (so-called "load following" and "ramping" products) that may assist in managing expected future increases in the amount of electricity provided by renewables that provide energy on a variable or intermittent basis, such as wind turbines.[115]

14.1.1. Commercial and Industrial Intermittent Resource Management Pilot

Under the C&I Base Intermittent Resource Management Pilot proposal, PG&E would work with the Demand Response Resource Committee to conduct a two-phase pilot. Phase 1 would consist of a scoping study that would examine the potential for use of thermal storage systems to assist with the integration of intermittent load from renewable sources. This phase would examine requirements for communication, automation, and other issues, and the development of a plan for conducting a field study. The second phase of this pilot would consist of field testing; during Phase 2, PG&E would install energy storage equipment in actual sites and evaluate the equipment's potential to assist

[115] PG&E Exhibit 201, Chapter 2, pp. 51 and 55.

CAISO in balancing energy supply and demand in order to safely integrate intermittent resources into the state's power grid.

14.1.1.1. Party Positions

TURN, Ice Energy and CAISO made comments on PG&E's C&I Intermittent Resource Pilot. Ice Energy suggests that PG&E should provide greater specificity in how it will integrate permanent load shifting with its renewable resources pilot.

TURN objects to this PG&E pilot proposal, arguing that the Commission should not authorize funding for PG&E's C&I Intermittent Resource Pilot because the utility has been integrating its existing resources into the grid for decades without demand response.[116] In addition, TURN argues that the utilities do not yet know how to integrate demand response with CAISO markets while ensuring ratepayers do not pay twice for the same megawatts, once as demand response and a second time as load to meet resource adequacy requirements.[117]

CAISO supports this pilot, asserting that efforts to understand how to integrate intermittent renewable energy sources using load shifting and storage should be expanded in anticipation of the possibility of increasing the state goal for energy from renewable sources to 33% of all energy by 2020. CAISO further suggests that as the amount of wind generation increases, the variability of wind turbine output could become greater than the variability of the load to be served, compounding costs and problems associated with integrating this load into the power grid. Finally, CAISO argues that it would cost less to investigate these

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[116] TURN Exhibit 418, p. 18.

[117] TURN Opening Brief, p. 34.

issues now rather than to wait and attempt to address them through a later pilot.[118]

14.1.1.2. Discussion

Ice Energy raises concerns about the lack of specificity on the uses of thermal energy storage technologies in the proposal for this pilot. The proposal does provide for a scoping study as a key element of Phase One, and notes specifically that the scoping study will include an examination of thermal energy storage features.[119] TURN objects to the study on the grounds that renewables that provide variable or intermittent load have been operating for years without creating difficulties for the power grid. CAISO disagrees with this statement, pointing out that the proportion of electricity provided by renewables is increasing rapidly, and that as the amount of power provided through renewables rises, the challenges of balancing supply with demand increase. We are persuaded that the challenge of keeping the power grid in balance grows as the amount of intermittent resources grows, and that it is advisable to study technologies and strategies that may assist with this integration before the electricity provided by intermittent resources increases enough to threaten the reliability of the grid.

To address the Ice Energy concern about the lack of specificity for this pilot, we direct the utility to use the planned scoping study as an opportunity to provide a greater level of specificity to demonstrate how it will integrate permanent load shifting technologies with the renewables pilot. PG&E shall

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118 CAISO Opening Brief, pp. 2-3.

119 Exhibit 205, Appendix 2C, p. 1 of Pilot 2a – C&I Based Intermittent Resource.

include a full discussion of permanent load shifting technologies and their potential for assisting with the integration of intermittent resources in the study to be prepared after the first phase of the pilot. With this requirement, we approve the C&I Intermittent Resources Pilot at the requested funding level of $1,764,000.

14.1.2. PHEV/EV Smart Charging Pilot

The PHEV/EV Smart Charging Pilot proposed by PG&E would test "Smart Charging" technology to charge electric vehicles without using electricity at times of peak demand or high energy prices. According to PG&E, the Smart Charging Technology integrates dedicated-electric or hybrid electric vehicles with their chargers, Advanced Metering Infrastructure networks, and Home Area Network Communications systems to determine when to charge vehicles. This so-called "intelligent charging system" would determine when to charge based on price signals or grid load requirements. This will help to ensure that such vehicles are charged efficiently and at relatively low cost, without increasing burdens on the power grid at peak times. PG&E requests $1,010,000 for this pilot.

14.1.2.1. Party Positions on the PHEV/EV Smart Charging Pilot

TURN's and CAISO's comments on this pilot largely echo those made by the same parties on the C&I Intermittent Resources Pilot.

14.1.2.2. Discussion

As discussed in Section 14.2.1.1.2, above, we are persuaded that the challenge of keeping the power grid in balance grows as the amount of intermittent resources grows, and that it is advisable to study technologies and strategies that may assist with this integration before the electricity provided by intermittent resources increases enough to threaten the reliability of the grid. Smart Charging technology that could assist customers in keeping efficient electric or hybrid electric vehicles charged without increasing peak system load is a promising method for moving electricity demand away from peak times, without creating inconvenience for customers. We approve the PHEV/EV Smart Charging Pilot with the requested funding of $1,010,000.

14.1.3. Small Customer Load Aggregation Pilot

The purpose of PG&E's proposed Small Customer Load Aggregation Pilot is to promote demand response enabling technologies for small customers in the commercial mass market sector. Specifically, PG&E proposes to equip small customers with switches and other controllable devices that can be triggered through a communication system in order to reduce load in end use devices. Although the project will not require customers to have interval meters, the utility explains that results gathered from the pilot will advance small customer participation in demand response after the utility's advanced meters, SmartMeters, are rolled out.[120] PG&E proposes to begin the pilot in 2009 with a request for proposals (RFP) to identify implementation and marketing vendors, and select technology. In 2010, the pilot will continue with customer acquisition, device installation, scheduled curtailments and monitoring. Following the pilot, PG&E intends to evaluate load drop and customer satisfaction of customers enrolled in the Pilot. The utility forecasts a total of $2.595 million for this pilot during the 2009-2011 budget cycle.[121]

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[120] PG&E Exhibit 201, Chapter 2, p. 2-58.

[121] PG&E Exhibit 201, Chapter 2, pp. 58-60, and budget on p. 1-13 listed as Small Customer Enabling Technology Pilot.

PG&E emphasizes that its proposed Small Customer Load Aggregation Pilot focuses on enabling technologies. This is unlike a previous load aggregation pilot focusing on small customers, which concentrated on outreach and understanding the needs and behavior of smaller customers. The utility notes that the budget for the pilot includes funding for the acquisition and installation of the enabling technologies to be tested in the pilot. PG&E also asserts that its pilot will prepare small commercial customers to move to dynamic pricing.[122]

14.1.3.1. Party Positions

SF Power originally argued that this pilot is unnecessary, and proposed that as an alternative, the Commission should authorize $675,000 for SF Power to extend its existing Small Customer Aggregation Pilot.[123] As discussed in Section 22, below, on March 25, 2009, PG&E and SF Power filed a motion for approval of a Settlement Agreement requesting that the Commission approve a continuation of the existing PG&E/SF Power Small Commercial Aggregation Pilot. In accordance with the terms of this settlement agreement, SF Power withdrew its opposition to PG&E's Small Load Aggregation pilot.[124]

14.1.3.2. Discussion

This proposal by PG&E is consistent with direction provided in the Guidance Ruling, which recommended that the utilities consider or propose a small load aggregation pilot in their 2009-2011 Demand Response applications.

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122 SF Power Reply Brief, p. 38.

123 SF Power Reply Brief, p. 23.

124 Settlement Agreement Between PG&E and SF Power, (see Attachment B for this decision) p. 9.

However, the Small Customer Load Aggregation Pilot, as proposed, is duplicative of two other proposals in PG&E's 2009-2011 demand response application, and therefore does not appear to offer additional value sufficient to justify the large expenditures requested. Specifically, PG&E proposes funding for enabling technologies similar to those used in this pilot in two other programs: Emerging Technologies and Automated Demand Response. The Emerging Technology proposal focuses on assessing hardware, software, design tools, strategies and services that may support demand response, including smart thermostats, smart appliances, energy storage, advanced lighting, advanced energy management systems, and technologies compatible with advanced metering infrastructure and home area networks (AMI/HAN). This list is substantially similar to the enabling technologies that PG&E proposes testing in this pilot.

Similarly, the Auto Demand Response Program (discussed in Section 12, above) is described as providing program participants with electronic, internet-based price and reliability signals that are linked to facilities' energy management control systems. Signals can be used to automate the response to dynamic pricing (such as the Critical Peak Pricing program) or demand bid options. Many of these technologies are appropriate for use by small commercial customers. The utility explained that in 2006-2008, only 10% of the Automated Demand Response came from the commercial sector. Though neither of Emerging Technology nor Automated Demand Response is specifically targeted to small commercial customers, the funding available through these programs could be available to such customers.

PG&E raises an important point that it may be beneficial to provide small commercial customers with opportunities and education to assist them in taking advantage of automated technologies;[125] this element of the pilot could be what sets it apart from the utility's Enabling Technology and Auto Demand Response proposals. Such a pilot could help prepare this customer class prepare for SmartMeter implementation, so that these customers will have the competence to choose to participate in a demand response program. However, in its proposal features section, the utility does not mention how it will provide education or technical help to customers and instead focuses on end use devices, control of devices and enrollment of customers. Further, the utility lists education as one element that bidders for RFPs should address, but provides no guidance.[126]

Based on PG&E's description included in the application, it is not clear that this pilot could meet the utility's objective to educate customers. It is also unclear whether or how this pilot would leverage information gathered from SF Power's final report on the existing Small Commercial Aggregation Pilot. PG&E also does not provide an explanation of why the activities contemplated for this pilot should not be funded through another source, perhaps the utility's budget for AMI deployment or the funds requested for Enabling Technologies or Automated Demand Response. For these reasons, we are not persuaded that PG&E should receive additional funding at this time for the proposed Small Commercial Load Aggregation Program, and the request for $2.595 million is denied. PG&E may conduct the activities described here through its approved Enabling Technology or Automated Demand Response budgets. PG&E and the other utilities are encouraged to submit a more specific proposal for a small load

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[125] PG&E Exhibit 201, Chapter 2, p. 58.

[126] PG&E Exhibit 205, Appendix 2D, pp. 1-3, Draft RFP Specifics for the Small Customer Load Aggregation Pilot.

aggregation pilot addressing issues such as education and outreach, if appropriate after the results of the ongoing Small Commercial Aggregation Pilot are finalized.

14.2. SCE

D.08-12-039 approved one Participating Load Pilot program proposed by SCE. This decision considers three additional proposals that would leverage the company's AMI system, Edison SmartConnect, "to enhance customer experience."[127] These three proposals are the Smart Thermostat Customer Experience Pilot, the Tier Alert Program, and the Optional Programmable Communicating Thermostat Program. SCE requests a total of $4,810,273 for these programs in 2009-2011.

14.2.1. SCE Proposals

14.2.1.1. Smart Thermostat Customer Experience Pilot

SCE proposes a Smart Thermostat Customer Experience Pilot to assist with the planned transition of its Summer Discount Program from an air conditioning direct load control program, utilizing one-way communication to activate simple on-off switches in return for a monthly credit, to a program that achieves load reduction through use of two-way communication with a smart thermostat, and pays participants for their actual load reductions. SCE intends to gather information from this pilot to prepare the utility for roll out of its advanced meters, Programmable Communicating Thermostats and default Peak Time Rebate tariff for residential customers. SCE proposes this pilot to help gain an

[127] SCE Amended Testimony Volume 1, p. 120.

understanding of program structure and operation issues such as customer Programmable Communicating Thermostat installation that could impact demand response or cause unnecessary program spending. The utility explains that 450 of the 500 customers needed for the pilot were already recruited prior to Resolution E-4169[128] and therefore many already have a Programmable Communicating Thermostat, and that some already have an interval meter. SCE forecasts spending $549,750 on this pilot for 2009 and 2010.

14.2.1.2. Proactive Residential Tier Alert

SCE explains that the SmartConnect infrastructure will include a web portal that uses data from meters to inform customers of their electricity usage, including the rate tier[129] applicable to the customer's usage at a given time. The utility proposes the Tier Alert program to notify customers up to three times per billing cycle when their level of usage is about to move the customer into the next rate tier for that month. SCE argues that this program will increase customers' awareness of energy usage and, as a consequence, energy conservation efforts.[130] The total forecast cost of this program is $3,459,849.

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[128] Resolution E-4169 is the resolution prepared to address SCE Advice Letter 2233-E, in which SCE had first proposed a similar pilot. In the original Advice Letter, SCE focused on conducting a behavioral study of its customers. The Advice Letter was rejected in this resolution because the Commission believed the proposal as designed would not provide the desired information. In addition, the advice letter was submitted too late for timely approval of the pilot for summer 2008.

[129] Utility electricity rates are structured in "tiers," with rates per unit increasing as the amount of electricity used per month increase. SCE has five rate tiers.

[130] SCE Exhibit 1, p. 121.

14.2.1.3. Optional Programmable Communicating Thermostats

Through its Optional Programmable Communicating Thermostat Proposal, SCE intends to assess the impact of use of a Programmable Communicating Thermostat on the load reductions of residential and small commercial customers enrolled in Critical Peak Pricing. SCE explains that it will use usage data to compare load reductions of these two customer groups during Critical Peak Pricing events. It appears that program activities would include solicitations, working with focus groups, and developing and evaluating survey instruments to evaluate and compare usage with and without Programmable Communicating Thermostats. SCE forecasts $780,674 for this activity in 2010 and 2011.[131]

14.2.2. Party Positions

TURN argues that the Commission should reject all three of the SmartConnect Enabled programs "based on the fact that Edison's AMI project has already been fully vetted and authorized through the AMI proceeding [A.07-07-026]."[132] TURN asserts that SCE's SmartConnect enabled programs should be reviewed in the context of the funding and programs that were already approved through D.08-09-039, which authorized activities and funding related to SCE's AMI deployment proposal. TURN contends that funding for SmartConnect was authorized based on an analysis of its estimated costs and benefits, and that authorizing additional money, would inappropriately

131 SCE Exhibit 1, p. 124.

132 TURN Opening Brief, p. 40.

undermine the earlier analysis by adding costs and benefits that have not been analyzed within the original business case framework.

TURN argues that the Optional Programmable Communicating Thermostat Proposal should be rejected because SCE did not meet the requirement in Resolution E-4169 that SCE present a well-designed research plan for this pilot.[133]

In addition to a similar objection to any program utilizing SmartConnect (or any other already-approve AMI system), CLECA expresses concerns about SCE's Tier Alert program. CLECA asserts that the goal of Tier Alert is to increase energy conservation, not to reduce peak energy usage, meaning that it is not a true demand response program. CLECA also objects to the Tier Alert program because it is targeted at residential customers only, arguing that the program should be funded by residential customers.[134]

14.2.3. Discussion

TURN suggests that these three SCE proposals should have been reviewed in the AMI proceedings. In D.08-09-039, which adopted the SmartConnect system, the Commission recognized that additional programs and services may be made possible by AMI in the future and may revisit future Commission policy decisions.[135] We anticipated that additional programs made possible by SCE's AMI might be proposed and approved in future Commission proceedings. It is not reasonable to deny funding to this pilot because it was not anticipated

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[133] TURN opening brief, p. 41

[134] Testimony of Barbara Barkovich, p. 53.

[135] D.08-09-039, Decision Approving Settlement on SCE's AMI Deployment, September 22, 2008, p. 18.

during a past proceeding. Instead, it is not only reasonable but in fact desirable to explore ways to leverage the ratepayers' investment that may provide additional benefits beyond those foreseen when the AMI project was approved. Therefore, we review the merits of each proposal individually.

14.2.3.1. Discussion of Smart Thermostat Customer Experience Pilot

TURN asserts that this proposal should be rejected due to the lack of an adequate research plan. However, SCE has improved its Programmable Communicating Thermostat proposal since it was initially submitted in SCE Advice Letter 2233. Appendix L of SCE's Amended Testimony includes a research plan for this proposal, and the current proposal reduces the cost of the program significantly. It is likely that information from this pilot will enable the utility to more effectively and efficiently provide customers with Programmable Communicating Thermostats and information needed to utilize that equipment more effectively. We approve this pilot at the requested funding level of $549,750 for 2009 and 2010.

14.2.3.2. Discussion of Residential Tier Alert

As noted by CLECA, the Proactive Residential Tier Alert proposal focuses solely on energy conservation, and is unlikely to result in any actual demand response. SCE has not made a persuasive argument that this program should be funded as a demand response program, and it is unclear whether the program would be cost effective. For these reasons, we deny SCE's request for approval and funding of its Tier Alert proposal. SCE may resubmit this proposal in a more appropriate proceeding, such as an application related to energy efficiency activities.

14.2.3.3. Discussion of Optional Programmable Communicating Thermostats

D.08-09-039 authorizing SCE's SmartConnect deployment approved $58.1 million for Programmable Communicating Thermostats.[136] This application requests an additional $780,674 for related activities in 2010 and 2011 to assess the effectiveness of Programmable Communicating Thermostats in increasing demand response. This program appears to be, essentially, a pilot to improve understanding of how customers that takes advantage of enabling technology, such as a Programmable Communicating Thermostat, perform on a Critical Peak Pricing rate. The requested funding is intended to support activities such as outreach and enrollment in the program, work with focus groups, and the development and evaluation of survey instruments to evaluate and compare usage with and without Programmable Communicating Thermostats. This proposal will leverage the $58.1 million already approved for Programmable Communicating Thermostats in order to improve understanding of customers' behavior. The information gained from this program may assist utilities in targeting distribution of Programmable Communicating Thermostats and improving consumer education related to use of Programmable Communicating Thermostats. This pilot should also improve understanding of customer behavior, and improve understanding of customer behavior.

We approve this proposal at the requested funding level of $780,674 as a pilot for the purpose of improving understanding of the impact of customer acceptance and behavior when given access to enabling technology such as Programmable Communicating Thermostats. In order to ensure that this

[136] D.08-09-039, p. 51.

information becomes publicly available, we require SCE to file a report on the pilot results with Energy Division not later than January 21, 2011.

14.3. SDG&E Residential Automated Controls Technology Pilot

SDG&E proposes a single pilot, the Residential Automated Controls Technology Pilot to test, implement, and evaluate enabling technologies that may assist in achieving load reduction during periods of peak energy use. The utility proposes testing energy management systems, programmable communicating thermostats, online curtailment tools, smart appliances and load control devices in conjunction with the deployment of the SDG&E Smart Meter (AMI) system. In order to enroll, customers will be required to have Smart Meters and electric appliances that may be curtailed in times of high use, and an average summer electricity usage of 700 kilowatt-hours per month.[137] SDG&E proposes to enroll up to 1,500 residential customers in this pilot,[138] focusing primarily on those with residences built before 1987. Participants will receive real-time energy usage information, as well as information on demand response events, and may participate in periodic surveys. Enrolled customers that maintain enabling technologies tested in this pilot will receive a bill credit of $1.25 per kilowatt-hour reduction achieved during SDG&E Peak Time Rebate events. SDG&E proposes a budget of $1,689,671 for the 2009-2011 budget cycle.[139]

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[137] SDG&E Exhibit 102A, p. 37.

[138] SDG&E Exhibit 102A, p. 35.

[139] SDG&E Exhibit 102A, pp. 37-43.

According to SDG&E, the Residential Automated Controls Technology pilot differs from existing enabling technology pilots in that it focuses on commercially available technologies (not testing of newly developed technologies). In addition, SDG&E suggests that the Residential Automated Controls Technology pilot will be larger than many previous pilots, and it will continue for a longer period of time, which SDG&E suggests will enable it to better evaluate customer acceptance, customer persistence, and customer preferences.[140]

14.3.1. Party Positions

TURN opposes the Residential Automated Controls Technology pilot, asserting that SDG&E already received funding for "all of its AMI- related programs, tariffs, and outreach programs."[141] TURN argues that "much of SDG&E's request [in this application] is inappropriate because it apparently seeks funding for programs that were, or should have been, authorized in SDG&E's AMI application."[142] TURN asserts that it is inappropriate for SDG&E to seek additional funds for its AMI project when that project's reasonableness was determined based on the costs and benefits submitted in A.05-03-015, and further, that SDG&E should be held to its claim made in testimony in that proceeding that AMI would result in lower spending on demand response programs beginning in 2009. In response, SDG&E argues that the savings estimates given in the earlier AMI proceedings are no longer relevant due to

140 SDG&E Exhibit 102A, p. 41.

141 Turn Opening Brief, p. 49.

142 Turn Opening Brief, p. 47.

delays in both its Smart Meter deployment and the implementation of its Peak Time Rebate tariff.

In addition, TURN argues that several previous studies related to Smart Thermostats have found high override rates and show limited success is demand reduction from in-home display devices.

14.3.2. Discussion

The Residential Automated Controls Technology pilot, as described, is designed to answer specific questions related to the willingness of residential customers to install enabling technologies that facilitate load reduction, as well as curtailment devices that allow the utility to control certain appliances. The pilot should also provide SDG&E with information that will allow the company to understand the information and support needs of customers, and evaluate how access to enabling technologies and increased information will affect residential customers' behavior, and the persistence of any behavioral changes and associated load reductions over time. Little information is currently available on which technologies best enable and encourage residential customers to engage in load reductions during demand response events, and the Residential Automated Controls Technology pilot could help provide this information.

We approved the settlement agreement in A.05-03-015 based on the best information available at that time. It is not reasonable to deny funding to this pilot because it was not anticipated during a proceeding that concluded two years ago, or because experience has shown that the reality of deployment does not perfectly match the estimates used in the approving decision. The Commission used the best information available in making that decision, and should not summarily dismiss new proposals that may build on the approved investment; new proposals should be judged on their own merits.

In D.07-04-043, which approved the Settlement for SDG&E's AMI application, the Commission recognized that AMI will support future technological advances. It would be misguided to limit the application of an investment to activities that were foreseen at the time the investment was approved. Instead, it is not only reasonable but in fact desirable to explore ways to leverage the ratepayers' investment in infrastructure such as the Smart Meter program, in an attempt to provide additional benefits beyond those foreseen when the project was approved.

The Residential Automated Controls Technology pilot is expected to provide information about residential customers' behavior, use of load control technologies, and willingness to participate in load management programs. Unlike many previous studies, the Residential Automated Controls Technology pilot will compare commercially available technologies and focus on their relative success, as well as the persistence of effects over a longer period of time. For these reasons, we approve the Residential Automated Controls Technology pilot and its associated budget of $1.7 million.

15. PG&E's Aggregator Managed Portfolio

PG&E's Aggregator Managed Portfolio program allows demand response aggregators who enter contracts with PG&E resulting from a competitive solicitation to establish their own aggregated demand response programs. PG&E currently has five contracts with aggregators. Approved in D.07-05-029, these contracts began in 2007, and require the aggregators to provide up to about 150 megawatts of demand response by 2011. These contracts act as Non-participating Load in the current CAISO market, since the contracts do not allow demand response events to be called by local capacity area.[143] These contracts are already approved by the Commission and in operation. No action on these contracts by the Commission is required in this decision.[144]

Like PG&E, SCE has several ongoing contracts with third-party demand response aggregators, which do not need to be addressed in this decision. SCE also requests approval of new contracts in its 2009-2011 application; these contracts are discussed in Section 19, below. SDG&E does not have similar aggregator contracts, and does not request authority in this proceeding to enter into any in this proceeding.

In the current application, PG&E proposes to issue a Request for Proposal (RFP) in late 2010 to replace its current aggregator contracts, which expire at the end of 2011. The purpose of such an RFP would be to replace the current contracts with contracts that could be more coordinated with the CAISO's new markets, possibly providing Proxy Demand Resource and/or Participating Load.[145] PG&E states "The replacement RFP and resulting contracts will incorporate CAISO's current MRTU phase requirements and will be callable within the Proxy Demand Resource (PDR) or Participating Load (PL) guidelines."[146] An RFP could also be used to solicit additional demand response capacity.

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143 PG&E, Exhibit 201 at 2-15.

144 In March 2009, PG&E filed a Petition to Modify D.07-05-029 seeking authorization to modify the terms of one of the five contracts. DRA has protested PG&E's petition.

145 Proxy Demand Resource and Participating Load are discussed in more detail in Section 16, below.

146 PG&E Exhibit 201.

It is not yet certain how demand response should be structured to participate most efficiently in California's future electricity market under the CAISO's new markets, to provide the greatest benefits to ratepayers in 2012 and beyond. One uncertainty is whether it will be necessary for aggregators to enter into contracts with utilities in order to provide demand response services to California customers. As directed by FERC in its Order 719,[147] CAISO is currently in the process of designing wholesale markets in which third-party demand response aggregators would be able to bid their clients' demand reductions directly into the markets, rather than providing this load reduction to the utilities, who would then bid the demand response into the markets themselves. This capability, often referred to as "direct bid-in" or "direct participation," could be available as early as 2010. Under direct bid-in, aggregators would receive payments through the CAISO markets for the demand response reductions they provide, instead of or in addition to payment through a utility.

If direct bid-in becomes available, it is unclear whether it would still be necessary or desirable for utilities to enter into contracts with third-party aggregators. In any case, it is possible that contracts of the type PG&E requests approval to solicit in 2011 will no longer be appropriate at that time.

The existing aggregator contracts (those previously approved by the Commission and those approved for SCE in this decision) will present a layer of complexity for both the CAISO and the Commission in terms of ensuring that the market functions properly and is competitive to the benefit of customers.

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[147] If such direct bidding is allowed by state and local market rules.

It is not necessary to determine at this time whether an RFP will be appropriate in 2011. There are reasons to believe that changes in the energy market over the next two years may affect the desirability of entering into new contracts for 2012 and beyond. It is reasonable to await additional information before approving the RFP request. PG&E and certain other parties suggest that the Commission should approve the PG&E proposal to issue an RFP despite the existing uncertainties. According to PG&E, this would preserve the possibility of entering into new contracts for 2012 but would still allow for the Commission to deny contracts negotiated on the basis of the RFP if appropriate. It is not reasonable to approve ratepayer funding for an RFP at this time given the uncertainty about the need for or desirability of contracts in 2012 or beyond. PG&E's request to issue an RFP to enter into new demand response contracts is denied without prejudice; PG&E may propose a similar RFP in the future, if appropriate based on market conditions.

In addition to PG&E's request to issue this RFP, PG&E also requests funding to support its existing aggregator managed contracts. The amount of funding needed to support these contracts is not clearly defined in the PG&E application, however, the Bridge Funding Decision granted PG&E $924,000 to support these activities in 2009. We authorize a total of $2,772,000 for administration of aggregator managed contracts in 2009-2011, three times the amount approved for aggregator managed contracts in 2009.

16. Program Transition to Function Under the New CAISO Markets

16.1. Background

MRTU is the CAISO's new design for wholesale electricity markets, which commenced on March 31, 2009. Through these markets, the CAISO ensures that there is sufficient energy to meet electricity demand in California at any given time to maintain the stability of the electrical system. Initially, the CAISO will recognize two types of demand response in the CAISO's new markets: Non-Participating Load and Participating Load. These demand response resources each have different levels of functionality and interaction in the CAISO markets.

One year after the CAISO's new market is implemented, the CAISO will introduce additional functions to the CAISO's market in an update called Markets and Performance. One of the enhancements that will be added at that time is Scarcity Pricing, a mechanism that raises certain prices to high, predetermined levels when electricity reserve margins (ancillary services) for a particular time fall below certain limits (in other words, when there is an increased probability of a shortage of electricity).

After the Markets and Performance update, the ISO will introduce Proxy Demand Resource. Proxy Demand Resource is currently under development through a CAISO stakeholder process. Proxy Demand Resource is intended to be a compromise between Non-Participating Load and Participating Load. Proxy Demand Resources would not have to schedule the underlying demand like Participating Load is required to do, but would be permitted to bid into the Day-Ahead Ancillary Service Markets and Real-Time Energy Markets unlike Non-Participating Load. Additionally, as currently proposed by the CAISO, Proxy Demand Resources would bid into the CAISO Markets at Custom Load Aggregation Points, while Participating Load bids at a nodal level and Non-Participating Load bids at a Default Load Aggregation Point.

Non-participating load has very limited functionality and will only be permitted to participate in the Day-Ahead energy market. Demand Response resources acting as Non-Participating Load can only mitigate scarcity prices indirectly by lowering load, which would then lower the amount of reserves required.[148] On the other hand, Participating Load can participate in the Day Ahead market and Real Time market, as well as the markets for ancillary services, and so will be able to address scarcity pricing directly. To qualify as Participating Load, a demand response provider must have a signed Participating Load Agreement with the CAISO for a particular activity or program, and must abide by stringent telemetry and metering requirements in order to provide Ancillary Services. Though not yet complete, because it is anticipated that Proxy Demand Resources will participate in the Day-Ahead and Real-Time energy market, as well as the market for ancillary services, Proxy Demand Resources will be able to address scarcity pricing directly.

Currently, the utilities' demand response programs provide load drops based on triggers that either are internal to the utility and not necessarily tied to market prices, or are connected to emergency conditions as declared by CAISO. Additionally, the notification times required by the retail programs are not well synchronized with CAISO market operations. In other words, existing utility retail programs do not incorporate market signals under the CAISO's new market, and so are not fully integrated with the anticipated wholesale markets: they can only qualify for CAISO purposes as Non-Participating Load. This lack of integration lessens the ability of demand response to reduce electricity prices in the market because demand response cannot necessarily be called upon to

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[148] The Reserve Requirement percentage would remain the same but the underlying MW amount needed to satisfy the percentage requirement would decrease.

reduce load at times of high prices or low reserve margins that do not result in an actual CAISO electricity emergency.

Recognizing this disconnect and the important role demand response can play in the CAISO's new market, the Guidance Ruling directed the utilities to submit plans in this proceeding outlining their strategies on how and when they will integrate their demand response retail programs with the CAISO's new market. In particular, the ruling emphasized the importance of positioning demand response resources as a tool to mitigate scarcity prices.[149]

In D.08-12-038, the Bridge Funding Decision in this proceeding, the Commission authorized four utility Participating Load Pilots, which are intended to enable the utilities to take existing retail demand response resources and dispatch these resources in the electric wholesale market and test ancillary services feasibility in summer 2009. The Commission expects much will be learned through these pilots to further shape the utilities' plans to integrate their programs with the CAISO's new market. This decision includes discussion of other participating-load related pilots, as well as the utility plans for transition existing programs away from non-participating load to either Proxy Demand Resource or Participating Load.

16.2. Utility Proposals for Transition of Demand Response Activities under the New CAISO Market

In these applications, the utilities suggest that full integration of demand response programs into the CAISO's new market is not possible until more information on the market's operation becomes available and further technical

[149] Guidance Ruling, pp. 16-17.

changes to utility systems can be implemented. SCE states that the utilities are unable to fully identify all of the technical and operational issues that must be addressed under the CAISO's new market.[150] For example, SCE states that it is limited in redesigning programs for the CAISO's new market until a comprehensive user guide for CAISO's demand response products that provides complete understanding of how demand response resources will be bid, dispatched, and settled in the CAISO's market, is made available.[151] Similarly, PG&E notes that CAISO's Scarcity Pricing design is still ongoing, meaning that how demand response resources will mitigate scarcity prices is still unknown. PG&E also discusses the need for enhanced communications,[152] and SCE and SDG&E express a need to complete installation of interval metering and telemetry in order to support Participating Load.[153,154] SDG&E also argues that issues such as direct access load forecasting, bidding into the CAISO's new market, and methods for settlement still need resolution.[155] For these reasons, all three utilities propose a gradual transition of demand response activities to greater functionality within the CAISO's new market.

PG&E asserts that Proxy Demand Resource can be implemented sooner and at a lower cost than Participating Load because the scheduling requirements for Proxy Demand Resource are much simpler. As noted above, Proxy Demand

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150 SCE Exhibit 2, p. 19.

151 SCE Exhibit 2, p. 37.

152 PG&E Exhibit 201, Chapter 3, p. 32.

153 SCE Exhibit 2, p. 7.

154 SDG&E Exhibit 101, p. 10.

155 SDG&E Exhibit 101, p. 8.

Resource only requires the submission of a load drop whereas Participating Load will require forecasting of a specific total load as well as the load drop, which will require increased planning time and forecasting effort.[156] Given the relative effort involved in transitioning programs from Non-Participating Load to Proxy Demand Resource or Participating Load, all three utilities focus their transition plans for 2010-2011 on evaluating their programs for transition to Proxy Demand Resource.

In its application, PG&E notes that, other than the Participating Load pilots approved in D.08-12-038, most of its demand response programs will participate as Non-Participating Load at the start of the CAISO's new market,[157] and proposes to phase some of its programs into greater alignment with the CAISO markets gradually, to allow for the development of the the CAISO's new market rules and PG&E procedures and infrastructure.[158] PG&E describes a plan to transition many of its current programs, as appropriate, from Non-Participating Load to Proxy Demand Resource beginning in 2010.[159] PG&E intends to transition its demand response programs to Proxy Demand Resource or Participating Load only after all changes to CAISO tariffs and procedures have been made and the necessary infrastructure is in place,[160] and when "the benefits justify the costs."[161] Because of this, PG&E's timeline for transition is not yet fully

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[156] PG&E Exhibit 201, Chapter 3, p. 19.

[157] PG&E Exhibit 201, Chapter 3, pp. 35-52.

[158] PG&E Exhibit 201, Chapter 3, pp. 1-2.

[159] PG&E Exhibit 201, Chapter 3, pp. 35-52.

[160] PG&E Exhibit 201, Chapter 3, p. 10.

[161] PG&E Exhibit 201, Chapter 3, p. 5.

defined and is partially dependent on outside factors and uncertain future analysis.

Like PG&E, SCE states that its demand response programs are currently limited to Non-Participating Load, with the exception of its previously approved Participating Load pilot programs. SCE expects that the Participating Load pilots taking place in 2009 will assist in resolving technical and operational issues and developing more detailed plans for transitioning demand response to provide more benefits under the CAISO's new market.[162] SCE proposes to begin bidding some of its demand response programs as Proxy Demand Resource as they conform to appropriate requirements over time. [163] SCE argues that it is not appropriate to take more immediate action until there is time to research customer needs, prepare internal systems and operations for compatibility with the CAISO's new markets, and if necessary, obtain Commission approval for its plans.[164] SCE also recommends that all investments made by SCE, the other utilities, and the CAISO should consider the optimal mix of demand response products. Like PG&E's transition plan, SCE's proposal is not yet very detailed, but moves in the direction of better integrating its demand response programs into the CAISO's new market.

Similarly, SDG&E states that it will redesign proposed programs as needed to enable participation in the CAISO's new market. Additionally SDG&E states it will submit new programs for Commission approval during the

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162 SCE Exhibit 2, p. 13.

163 SCE Volume II, p. 10.

164 SCE Volume II, p. 13.

2009-2011 cycle if the opportunity to improve integration with the CAISO's new market arises.[165]

Each utility will run at least one pilot during the summer of 2009 to test the ability to use various demand response resources as Participating Load, and the results of these pilots are expected to provide information that can be used to transition programs to Proxy Demand Resource or Participating Load starting 2010. PG&E and SCE both suggest that the transition of programs to Proxy Demand Resource or Participating Load will require additional funding beyond the amounts requested in this proceeding.

16.3. Party Positions

Very few parties provided detailed responses to the utilities' MRTU transition proposals. TURN takes the position that the time and expense required to transition programs to function as Participating Load may not be cost effective, and proposes that the Commission minimize expenditures on compatibility with the CAISO's new markets, and focus on simpler ways of integrating demand response into them in the short run, while delaying the transition of utility programs to operate as Participating Load. [166] CAISO, on the other hand, generally supports the transition of programs to operate as Proxy Demand Resource or Participating Load, asserting that demand response that can participate in the real time market would be extremely valuable.[167] CAISO also offers a few specific responses to utility assertions on the amount of information available or needed to transition certain programs, suggesting that

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[165] SDG&E Prepared Testimony of Mark Gaines, Volume I of VI, p. 6.

[166] TURN Exhibit 420, pp. 5-6.

much information about the CAISO's new market and scarcity pricing is already available to be used in planning program transitions.[168]

16.4. Discussion

It appears that it is not feasible at this time to install the infrastructure and processes needed for anything more complicated than Non-Participating Load for 2009. Given this, a gradual transition of some programs from Non-Participating Load to Proxy Demand Resource and a few ultimately to Participating Load, as outlined by the utilities, is reasonable. This will allow the development of additional information on the operation of Proxy Demand Resource and Participating Load, along with the implementation of technical changes and education programs that will facilitate the transition. Still, these transition plans are vague and raise several issues and barriers that should be explored while the transition is ongoing.

It is true that the CAISO's final design of Scarcity Pricing is incomplete. However, it is well known that the triggers Scarcity Prices will be based on the CAISO's ancillary service reserve margin. Additionally, there is consensus amongst participants in the CAISO's Scarcity Pricing stakeholder process regarding the products that will be subject to Scarcity Pricing, including Non-spinning Reserves, Spinning Reserves, and Regulation (both upward and downward). The requirements of these products are established by the Western Electricity Coordinating Council (WECC), are well defined, and are not likely to change. As noted above, Demand Response acting as an ancillary service

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[167] CAISO comments on amended application, September 29, 2008, p. 14.

[168] CAISO comments on amended application, September 29, 2008, p. 10.

resource will mitigate Scarcity Pricing much more effectively than Demand Response acting as an energy resource. However, none of the utilities propose a plan that will put demand response in a position to reasonably mitigate scarcity prices because none of the programs allow utilities' Demand Response to participate in CAISO markets as ancillary services.

The other barriers and uncertainties raised by the utilities in support of their proposals for a gradual transition to Proxy Demand Resource and Participating Load include CAISO's completion of comprehensive User's Guides for Proxy Demand Resource and Participating Load and the need for more information on demand response aggregators' role in the CAISO's new market. We agree that it is difficult for the IOUs to create the necessary infrastructure and communications networks without knowing the final market designs. These concerns all support the need to continue information gathering and analyses on the expected place of demand response programs within the CAISO's new market. For example, the Participating Load Pilots approved for 2009 are expected to provide a great deal of relevant information. Because the Participating Load Pilots are designed to test Participating Load, the most complex demand response product, these pilots should provide the utilities with opportunities to design and test networks that are able to integrate demand response resources into the CAISO's new market as Non-Participating Load, Proxy Demand Resource, and Participating Load.

It appears that several significant milestones will be reached over the next two years. The first milestone is the completion of the Participating Load Pilots during the summer of 2009. As noted earlier, these pilots will provide information regarding the needed infrastructure, communications, and metering technologies required for Participating Load. The second milestone is CAISO's completion of its market designs and user guides for Proxy Demand Resource and Participating Load, expected sometime in the fall of 2009. The third milestone is the participation of utility demand response programs as Proxy Demand Resource in summer 2010. As noted earlier, the CAISO is projecting that it will have a Proxy Demand Resource product in place for use during the summer of 2010, and that the utilities will transition some demand response programs to Proxy Demand Resource for 2010 participation.

We agree that it would be best to wait to make major changes to programs until the benefits of those changes are found to outweigh the costs. We believe that the determination that the benefits of a major change outweigh its costs is best made by the Commission after the demand response opportunities and their costs and benefits under the CAISO's new market can be better defined. The current gaps in our knowledge may be addressed through the results of the Participating Load Pilots, which are expected to provide a great deal of information regarding the costs of such changes. The final designs for Proxy Demand Resource and Participating Load will also affect the implementation costs for the utilities, as will the utilities' experience with Proxy Demand Resource in 2010. However, we do not consider altering at least one program to be compatible with the CAISO's non-spinning and/or spinning reserves products to constitute a major change.

We approve the utilities' existing MRTU transition plans for 2009-2011, with the following additional requirements. As noted earlier, the utilities' integration plans indicate that moving demand response programs to Participating Load will be more complex and difficult than transitioning them to Proxy Demand Resource. In order to address these difficulties and ensure that programs are transitioned in a thoughtful way when such changes are deemed to be cost effective, we require the utilities to prepare two reports over the next two years. First, the utilities shall file an evaluation of the Participating Load pilots in 2009. The evaluation will provide an assessment of what was learned through the pilots, areas that need further exploration (if any), and potential next steps for 2010 and beyond. This evaluation will be due by December 31, 2009.

In addition, the utilities will prepare and submit detailed reports on the transition of demand response programs into the CAISO's new market by January 31, 2011. These plans shall include lessons learned from the utilities' 2009 pilots and their 2010 Proxy Demand Resource experience, including performance assessments as well as an evaluation of expected costs and benefits of integrating all programs into Proxy Demand Resource (if such programs have not already been integrated) and Participating Load (for all programs). As part of each transition plan, the utility should also include a description of its analysis in determining the appropriate level of integration into the CAISO's new market (Non-Participating Load, Proxy Demand Resource, or Participating Load) for each of their demand response programs, and the rationale for their recommendations. These reports should also include an assessment of the probable effect of each program on Scarcity Pricing. The plans should also provide information on any barriers that still exist for integration to Proxy Demand Resource and Participating Load, and suggest next steps as to how to address those barriers.

In order to ensure steady progress towards integration with the CAISO's new markets, the Commission directs the utilities to propose modifications to one or more existing demand response programs that will make at least 10 percent of the megawatts enrolled in the demand response programs authorized in this decision comply with the CAISO's Proxy Demand Resource requirements.

These required program modifications should be requested within 30 days of the filing of CAISO's Proxy Demand Resource tariff with the Federal Energy Regulatory Commission. We expect the transition to Proxy Demand Resource to involve modifying one or more of the following programs: the Capacity Bidding Program, the Demand Bidding Program, PG&E's PeakChoice, SCE's Energy Options program, or a utility's contract with an aggregator. Because these changes are unlikely to affect the utilities' overall demand response budgets adopted in this proceeding, we expect these changes to be requested via Tier 2 advice letters, consistent with the rules for program and budget changes adopted in this decision.[169]

In addition, within 30 days of the approval of CAISO's Proxy Demand Resource tariff by the Federal Energy Regulatory Commission, each utility shall file a proposal with the Commission to make at least one program comply with the 10-minute dispatch notification time requirements for participation in the CAISO's ancillary services market as either Proxy Demand Resource or Participating Load. Utilities may choose to create a new program, a new option within in existing program, or modify an existing program such as its Capacity Bidding Program, the Demand Bidding Program, PG&E's PeakChoice, SCE's Energy Options program, or a utility's contract with an aggregator. These requests shall also comply with the rules for program and budget changes adopted in this decision; changes that require additional funding beyond the total approved in this decision, or creation of an entirely new program, may require an application or petition for modification, as discussed in Section 25,

[169] As discussed in Section 25 below, changes to aggregator contracts will require new applications or petitions for modification of the decisions adopting those contracts.

below. All other metering and telemetry requirements for demand response participation in the CAISO's ancillary service markets are subject to CAISO review and approval.

All demand response activities that are not transitioned to Proxy Demand Resource or Participating Load shall continue to be scheduled in the CAISO day-ahead market as Non-participating Load. Utilities will comply with existing CAISO requirements for Non-participating Load. These requirements include the elimination of the manual work-arounds used to account for demand response by reducing the level of Residual Unit Commitment procured by the CAISO, and submission of a price-curve on desired load purchases, allowing the utility to forego the purchase of energy at a price at which a demand response program will be triggered.

17. Settlement Baseline for Utility Programs

17.1. Current Baseline for Settlement and Studies

Some demand response programs pay a customer for reducing its usage during demand response events. Since a customer's meter only measures how much energy a customer actually used, the reduction in energy use must be estimated by estimating how much energy the customer would have used if a demand response event had not been declared. The estimate of energy use in the absence of a demand response event is referred to as the "baseline."[170] An important issue in this proceeding is determining whether the existing baseline

[170] In contrast, a baseline is not necessary for dynamic pricing rates, which generally charge a customer variable prices for the energy that the customer actually uses.

methodology for utility programs should be changed, and, if so, to what alternative baseline method.

The utilities currently use a "3-in-10 unadjusted baseline" method in most demand response programs. This method takes the average of a customer's energy use during the three highest days out of the last 10 business days. The 10 business days exclude any event days and holidays. The baseline is "unadjusted" in that the calculated average is not adjusted up or down based on the usage the morning of the event. In these applications, the utilities offer various proposals for changing the settlement baseline in the 2009-2011 period.

17.2. Utilities' Baseline Proposals

For customers with loads greater than 200 kilowatts enrolled in most of its demand response programs, PG&E proposes to replace the 3-in-10 unadjusted baseline with a "10-in-10 adjusted baseline," under which a customer's baseline would be calculated as the average of that customer's energy use during the 10 previous non-event business days, adjusted up or down based on the customer's usage in the four hours immediately before the event, a so-called "default morning-of adjustment."[171] PG&E proposes allowing customers to opt out of the adjustment, in which case the baseline would be the average of the 10 previous non-event business days. PG&E proposes that customers with loads under 200 kilowatts should not be offered the morning-of adjustment, stating that it would not be feasible to develop, administer, and implement for mass market customers during 2009 though 2011.[172] PG&E proposes this new 10-day

[171] Exhibit 201, pp. 2-29.

[172] PG&E 2009-2011 Demand Response Programs and Budgets Amended Prepared Testimony, September 19, 2008, p. 2-30.

baseline approach be phased-in starting in 2009, applied first to its PeakChoice program, Optional Binding Mandatory Curtailment Program, Capacity Bidding Program, and Business Energy Coalition Program. PG&E would maintain the current 3-in-10 baseline for ABEC and Demand Bidding Program.[173]

In contrast, SCE proposes to retain the current 3-in-10 day baseline as a default baseline for its Energy Option program, but provide customers with the ability to choose a 10-in-10 day baseline with a day-of adjustment.[174] SCE does not specify how it would calculate its day-of adjustment used with its 10-in-10 baseline, or whether SCE intends to extend this baseline option to other programs. SDG&E does not propose changes to its existing baseline methodology.

17.3. Party Positions on Appropriate Settlement Baselines

17.3.1. Individual vs. Aggregated Baselines for Aggregator-Managed Customers

CDRC proposes to use an individual baseline for aggregated programs. In this method, the hourly loads for each of an aggregator's customers are used separately to identify that customer's highest 3-in-10 days (or 5-in-10, or 10-in-10, depending on the methodology). The average loads over those three days (or five or ten) are calculated, and then the individual customer baseline loads are summed up to produce the total aggregator baseline load for each event-type day. The resulting sum of individual baselines is then compared to the actual

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[173] Demand Bidding Program will be phased out at the end of 2009.

[174] SCE Volume I, Amended Testimony in Support of SCE's Amended Application for Approval of demand response Programs, Goals, and Budgets for 2009-2011, September 19, 2008, p. 21.

sum of the usage of those same customers. Nonetheless, CDRC argues that no party has argued that individual baselines are not preferable for customers.

In contrast, utilities use an "aggregated baseline" for all customers enrolled in a demand response program through a third-party aggregator. This allows the utilities to compensate the performance of the aggregated resource as a whole. Under the "aggregated baseline" method, the hourly load for all of an aggregator's nominated customers are summed, and the resulting aggregator loads are used to identify the three days in the past 10 (or 5-in-10, or 10-in-10) in which total usage of all customers enrolled through that aggregator was highest. The average loads over those three days (or five or ten) are calculated. The resulting aggregator baselines are then compared to the actual aggregator load for each of the event days.

In its opening brief, SCE asserts that the use of individual baselines for aggregated programs would overstate load reduction and, in some scenarios, could result in a payment for a load reduction that did not occur. SCE claims, "Unbundling the estimation of baseline through the individualized approach recommended by the CDRC distorts the impact of the aggregated resource by 'cherry picking' individual customers for the usage on different peak days that maximizes their individual contribution, not the coincident contribution of the aggregated resource. This unbundling effect would relieve the aggregator of its responsibility to manage the aggregated resource for the coincident impact and unfairly reward passive resources."[175] PG&E agrees with SCE, and argues that aggregators have access to PG&E's meter data and can use it to verify each

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[175] Opening Brief of Southern California Edison Company in A.08-06-001 et al., January 28, 2009, p. 33.

customer's individual performance. Both PG&E and SCE argue that aggregators have the ability to provide individual customer baselines to assist these customers, if appropriate.[176] PG&E and SCE state that aggregators are compensated to manage the customers they enrolled, and that utilities do not know how the aggregators compensate their individual customers.[177] PG&E does acknowledge an ongoing study by Christensen Associates that examines the issue of individual baseline versus aggregated baseline, and suggests that any decision in favor of an individual baseline should be deferred until the outcome of the study.[178] This study, which was filed with the Commission in April 2009, has not been entered into the proceeding record, and therefore is not considered here.

17.3.2. Average Day Calculation

TURN and CDRC disagree with some or all of the utilities' baseline proposals in these applications.[179] TURN objects to SCE's proposal to retain the current 3-in-10 day baseline as a default, and urges the Commission to require ongoing monitoring of baseline accuracy. TURN notes that the 2008 study by Christensen Associates finds that the unadjusted 3-in-10 baseline tends to overstate actual loads on event days for many SCE customers, thereby promoting free ridership and resulting in higher payments than appropriate to

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[176] SCE Reply Brief, p. 9. PG&E Reply Brief, p. 30.

[177] SCE Reply Brief, p. 10. PG&E Reply Brief, p. 31.

[178] PG&E Opening Brief, p. 21.

[179] Exhibit 705 and Exhibit 420, p. 10.

some customers.[180] TURN proposes that the Commission implement the finding of the Christensen study[181] that recommends customers with high load-variability should be guided toward demand response programs that do not require baseline calculations, such as Critical Peak Pricing.

CDRC proposes a 5-in-10 baseline with an asymmetrical (upward only) day-of adjustment capped at 20%. PG&E argues that the 5-in-10 baseline is not recommended by any studies. CDRC acknowledges that research does not indicate that one methodology is superior, but proposes a 5-in-10 baseline as a "compromise" between the 3-in-10 baseline currently used and the 10-in-10 baseline proposed by PG&E. In a reply brief, PG&E acknowledges that the 5-in-10 (adjusted) method has its own merits under certain situations, but the KEMA report cited by CDRC recommends overall that the adjusted 10-day model with a two-way adjustment be used in most situations. Both SCE and PG&E assert that the consideration of this should await the results of PG&E's baseline pilot, which tested a temperature-sensitive baseline using a "morning of" adjustment to the current "3-of-10" baseline methodology, capped at 20%, similar (though not identical) to the baseline adjustment CDRC proposed in this proceeding. In comments on the proposed decision, CDRC reiterates its recommendation, asserting that a 10-in10 day baseline may significantly understate usage for certain customers.

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180 Christensen Associates Energy Consulting, LLC, S. Braithwait, M. Welsh, D. Hansen, and D. Armstrong, "California Day-Ahead demand response Program Baseline Load Analysis and PY-2006 Impact Evaluation – Final Report," June 6, 2008, pp. 8-12.

181 Exhibit 420, p. 10.

17.3.3. Adjustment

PG&E proposes to adjust the 10-in-10 baseline based on customer usage during the four hours prior to the beginning of an event. PG&E argues that the hours immediate preceding the event should be used (and not hours further removed from the event start time) in order to avoid gaming. Gaming of a baseline that allows adjustment of a calculated daily average for usage before an event can occur if a customer deliberately increases its load in the morning before the event to inflate the baseline. PG&E believes that using a relatively large period of time (e.g., four hour) to calculate the adjustment discourages gaming by making gaming more costly to participants, whose electric bill would increase during the whole adjustment period.

CDRC proposes to use a five-hour window prior to the event start time, and to use only the first three hours of that window to determine the adjustment. CDRC asserts that some customers are penalized under PG&E's suggested four-hour adjustment because they begin curtailment actions before the beginning of an event, for example ramping down manufacturing or lighting to ensure load drop at the very beginning of an event.[182] PG&E argues that this window period used to calculate the adjustment is too far from the event window, and will lead to a less accurate adjustment.[183] PG&E does not oppose CDRC's proposal in concept, but believes there should be a shorter gap between the adjustment calculation window and the event window, such as using the first three hours of a four-hour window prior to the event.[184] In its reply brief, CDRC

[182] CDRC Opening Brief, p. 39.

[183] PG&E Opening Brief, p. 22.

[184] PG&E Opening Brief, p. 22.

believes that PG&E's recommendation to measure the morning-of adjustment period using the first three of the four hours prior to the event is reasonable.[185] In comments on the proposed decision, CDRC further recommends that if a 10-in-10 day baseline is used (rather than CRDC's preferred 5-in-10 methodology), the maximum adjustment should be raised from plus or minus 20% to plus or minus 35%, to offset the possibility that the 10-in-10 day baseline may understate certain customers' usage.

17.4. Baseline Recommendations

A properly designed baseline calculation methodology is important for the success of any demand response program as it provides the benchmark by which performance is measured. A methodology that systematically over-estimates "business as usual" loads will over-value the contribution of a demand response resource and pay a customer for demand reductions that did not actually occur. Conversely, a baseline methodology that under-estimates the "business as usual" loads will under-value the demand response reduction provided by a customer and not provide the appropriate compensation.

Two studies[186] have examined the performance of various baselines in recent years. The studies uniformly suggest there are better baselines than the current three-day unadjusted baseline for the large commercial and industrial

[185] CDRC Reply Brief, p. 13.

[186] Exhibit 210 - Protocols Development for Demand – Response calculations: Finings and Recommendations, Prepared for the CEC by KEMA-Energy. CEC 400-02-017F; Exhibit 211 - Evaluation of 2005 Statewide Large Nonresidential Day-ahead and Reliability Demand Response Programs. Prepared for Working Group 2 Measurement and Evaluation Committee, by Quantum Consulting Inc. and Summit Blue Consulting, LLC 2006.

customers. The studies also conclude that a day-of adjustment based on usage data from the morning before an event can significantly reduce the bias and improve the accuracy of this type of baseline. The regression methodology used by SDG&E is generally accepted to be reasonably accurate, but has the disadvantage of being complex and costly to calculate, and difficult for participants to understand.

Based on the record of this proceeding, including various studies, there is no one single baseline that will provide accurate settlement calculations for all customers. The KEMA 2003[187] study suggested that a good baseline for settlement should be simple to calculate, unbiased, predictable to customers prior to an event, and minimize the possibility of gaming. Both KEMA 2003 and Quantum 2006 studies recommend a 10-day baseline with a day-of adjustment. This approach calculates an average for each hour, using the last 10 weekdays prior to an event, excluding any event days and holidays prior to the event. The day-of adjustment is a ratio of (a) the average load of certain hours before the event to (b) the average load of the same hours from the last 10 weekdays, excluding event days and holidays. KEMA suggests that this method performs well for both weather-sensitive and non-weather sensitive customers in its sample.

Based on the record presented in this proceeding, we adopt a 10-in-10 baseline with a day-of adjustment, and require that an individual baseline be used for customers enrolled in a utility demand response program directly through a utility and for customers enrolled in these same programs by

[187] Exhibit 705, Attachment 15.

an aggregator.[188] The adjustment will be symmetrical (upward or downward, as indicated by usage in the window time period), is capped at 20%, and will be based on the first three of the four hours prior to the event. Utilities shall offer customers the opportunity to opt in to the adjustment. This change in the baseline should be applied to Capacity Bidding Program, Demand Bidding Program, Optional Binding Mandatory Curtailment Program, PG&E Peak Choice, and SCE's Energy Options program.

The adopted approach will provide customers with a relatively simple and understandable baseline that minimizes bias and the possibility of gaming by participants. It is reasonable for customers to have their baselines calculated in the same way, whether they enroll in a program through an aggregator or through a utility. Similarly, it is reasonable for customers of SCE, SDG&E, and PG&E to be subject to the same baseline. This will make the baseline methodology more consistent and transparent to customers.

The Commission agrees with TURN's recommendation that in the long term, utilities should attempt to steer customers with highly variable loads away from demand response programs that require baselines, and towards programs that do not require baseline calculation such as Critical Peak Pricing. To facilitate this, we direct the utilities to work with parties for an agreement on the definition of highly variable load customers, and to prepare and file a report in R.07-01-041 or a successor proceeding by September 1, 2010, on the definition of highly variable load customers along with an estimate of the number of highly variable load customers that are currently in its baseline demand response

[188] This requirement does not apply to demand response contracts between a utility and an aggregator approved by this Commission that specify a baseline as part of a contract.

programs, and the number of megawatts contributed to the programs by those customers. This report will also include information on the proportion of customers choosing the morning-of adjustment option that reach or exceed the maximum adjustment of 20%, and how often that maximum adjustment is reached. This information will assist us in reviewing the effectiveness of the 20% adjustment. The report should propose a plan for steering highly variable load customers towards demand response programs that do not require baseline calculation.

18. Concurrent Customer Participation in Multiple Demand Response Programs

In the past, customers have generally been able to participate in only one demand response program or dynamic pricing tariff at one time. As dynamic tariffs become more common and the utilities implement default Critical Peak Pricing, current rules against participation in more than one demand response program or tariff may limit the amount of peak load reduction that can be achieved through demand response. For this reason, several parties to this proceeding advocate for new rules that would allow customers to participate in more than one demand response program, in an effort to capture more peak load reduction when it is needed.

18.1. Utility Proposals for Concurrent Customer Participation in Two Demand Response Programs

SCE advocates for maintaining rules against allowing an individual customer to participate in more than one program, arguing that allowing dual program participation could potentially lead to double payment to customers for a single load drop.[189] SCE's application states, "… SCE's [demand response] programs and dynamic tariffs should encourage customers to select the single program or tariff that is best suited to each particular customer's situation."[190] Still, SCE acknowledges that it may be useful to allow dual participation in certain limited situations or between specific programs in which the risk of double payment is minimal or can be avoided, and suggests a few situations in which dual participation may be possible. SCE also recommends reevaluating participation requirements in 2012.[191]

SDG&E currently allows individual customers to participate in certain combinations of existing demand response programs, and supports increasing the opportunities for a customer to simultaneously participate in two demand response programs.[192] SDG&E reasons that, "… permitting multiple program participation will allow customers to respond more effectively to the need for load reduction under a mix of differing circumstances; restricting customers' participation to just a single program limits this flexibility to respond under a variety of circumstances."[193] SDG&E anticipates that allowing customers greater flexibility to participate in a mix of programs will ultimately lead to the availability of more demand response in the state. SDG&E agrees with SCE that it is important to avoid duplicative incentive payments for the same load

[189] Ibid.

[190] Exhibit 2, p. 14.

[191] Exhibit 2.

[192] Exhibit 7, pp. 72-73.

[193] Exhibit 7, pp. 72-73.

reduction.[194] In order to accomplish this while facilitating participation in two programs, SDG&E proposes establishing processes and safeguards so that customers do not receive multiple or duplicative incentives for the same load reduction, and to ensure that load reductions are credited to the appropriate program(s) through a program hierarchy mechanism.[195]

SDG&E envisions rules for demand response programs that would permit customers to enroll in more than one program if the programs have differing triggers, and advocates for establishing a system to measure load reductions in order to allocate the load drop appropriately among the programs responsible for producing them.[196] In those instances in which the load reduction cannot be measured for specific program allocation, SDG&E describes a possible program hierarchy that would determine which program gets credit for the load reduction, and what incentive payment the customer should receive.[197] Like SCE, SDG&E provides a matrix outlining dual program participation guidelines in an appendix of its testimony.[198]

Like SCE and SDG&E, PG&E states that its current demand response dual program participation rules are based on the premise that a customer should not be paid twice for the same load reduction.[199] PG&E explains that its demand response program portfolio allows concurrent participation in specific

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[194] Exhibit 7, p. 76.

[195] Exhibit 7, p. 76.

[196] Exhibit 7, p. 75.

[197] Exhibit 7, p. 75.

[198] Exhibit 7, Appendix C.

[199] Exhibit 201, Chapter 2, p. 23.

combinations of demand response programs, and advocates for limiting customers' ability to enroll in two programs.[200] PG&E suggests that utilities should be allowed to request authority to modify the dual program participation rules ultimately approved in this proceeding if they find that they are unable to make reliable demand response load reduction forecasts for the CAISO. PG&E also points out that the outcome of the 2008 Rate Design Window and Phase 2 of the 2011 General Rate Case may necessitate a change in the ability of Real Time Pricing customers to participate in additional demand response programs. Like SCE and SDG&E, PG&E provides a chart outlining dual program participation guidelines.[201]

SCE, SDG&E and PG&E all support the idea that a customer should not be paid twice for the same load reduction. Still, based on their discussions and lists of possible program combinations, it appears that SCE and PG&E have a much narrower view of how much dual program participation is appropriate. SDG&E seems to offer the broadest support for dual program participation by proposing processes and safeguards to facilitate smooth operation and implementation.

18.2. Party Positions on Dual Program Participation

Parties offer varying opinions about the appropriateness of allowing customers to participate concurrently in two demand response programs. DRA asserts that SDG&E does not explain how it evaluates programs when a

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[200] Exhibit 201, Chapter 2, p. 23.

[201] Exhibit 201, Chapter 2, p. 25.

customer participates in two programs.[202] DRA also questions the SDG&E proposal for allocating load reductions to specific programs, how incentives for avoided capacity costs can be calculated for each program when a customer participates in two programs, and how SDG&E will avoid paying duplicative incentives. DRA also expresses concern that barriers to customer participation in more that one demand response program may result in loss of potential load reductions from demand respond.[203]

Consumer Powerline expresses strong support for equal treatment among third party and utility demand response programs.[204] Consumer Powerline also asserts that the utilities should allow customers to participate concurrently in more than one demand response program, including programs run by third-party demand response aggregators, "unless this can be shown to be infeasible."[205] Similarly, the Joint Parties recommend that the utilities should allow commercial and industrial customers to simultaneously participate in two demand response programs, including offerings from aggregators.[206] The CLECA also supports dual program participation, specifically "that there should be provision for dual program participation and… that customers participating

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202 Protest of The Division of Ratepayer Advocates, filed July 9, 2008 in A.08-06-001 et al., p. 6.

203 DRA Protest of Amended Applications, filed September 29, 2008 in A.08-06-001 et al., p. 4.

204 Response of Consumer Power Line ("CPLN") to Applications, filed July 9, 2008 in A.08-06-001 et al., p. 2.

205 Response of Consumer Power Line to Applications, filed July 9, 2008 in A.08-06-001 et al., p. 5.

206 Comments of the Joint Parties, filed July 9, 2008 in A.08-06-001 et al., p. 2.

in PG&E's RTP should be allowed to participate in any other [demand response] program(s)."[207]

CDRC specifically identifies SCE's Default Critical Peak Pricing Program as a program that should be modified to allow customers to also participate in day-of options of programs, such as the bilateral contracts and Capacity Bidding Program. The CDRC supports SDG&E's determination that it is appropriate to establish a framework for dual program participation that permits customers to enroll in programs with different trigger events.[208] According to CDRC, utility proposed commercial and industrial demand response programs should be open to Demand Response Providers including access to incentives.[209]

On October 9, 2008, SCE filed reply comments stating that, "… it is open to the idea of providing customers additional program choices as long as double dipping and double payments are avoided."[210]

PG&E contends that allowing customers to participate concurrently in demand response programs run by aggregators and utilities would complicate load drop forecasts and lead to other problems. PG&E suggests if multiple programs called events at the same time, "[s]uch a situation would result in an inaccurate forecast to the CAISO and possible double counting and double-

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207 Comments of CLECA, July 9, 2008, p. 6.

208 Comments of CDRC on Amended Applications, filed September 29, 2008 in A.08-06-001 et al., p. 13.

209 CDRC Opening Brief, pp. 11, 12.

210 CDRC Opening Brief, pp. 8.

payments in dual participation situations."[211] PG&E maintains that demand response program forecasts are used for resource adequacy consideration and load forecasting accuracy is diminished by mixing day-ahead programs and day of programs between aggregators and utilities.[212] PG&E argues that allowing participation in multiple demand response programs could cause resource planning and system reliability problems.[213] PG&E notes that its current rules allow a customer to participate in a capacity-payment program and an energy-payment program, but not in two capacity payment programs or two energy payment programs. [214] According to PG&E, this minimizes the possibility of double payments for a single load drop. PG&E states that its approach to dual program participation balances the need to give flexibility to customers, obtain maximum load impacts, and provide an accurate demand response forecast to the CAISO.[215] SCE contends that there are "…administrative complexities related to adjusting incentive payments for dual participation customers [raising the possibility of] increased administrative costs and customer confusion."[216] In comments on the proposed decision, SCE, PG&E, and CLECA strongly object to considering critical peak pricing, noting that for some utilities, the critical peak pricing tariff constitutes a reduction in customer demand charges, and that when

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211 Reply of Pacific Gas and Electric Company (U 39-E) To Protests and Responses to Amended Application For Approval of 2009-2011 Demand Response Programs and Budgets pp. 6-7.

212 Ibid, p. 34.

213 Reply Brief of Pacific Gas and Electric Company, February 11, 2009, p. 33.

214 Reply Brief of Pacific Gas and Electric Company, February 11, 2009, p. 33.

215 Opening Brief of Pacific Gas and Electric Company (U 39-E), January 28, 2009, p. 25.

216 Ibid., p. 15.

this discount is combined with the Base Interruptible Program rate, could lead to customers receiving negative demand charges.

SCE considers Critical Peak Pricing to be a capacity-based program, and would permit dual participation in Critical Peak Pricing and energy-based programs only. CDRC argues that Critical Peak Pricing is an energy-based program, because it provides incentives in the form of lower energy rates during off-peak hours.[217] SDG&E and CLECA reached an agreement regarding the interaction of the summer saver program and peak time rebate programs. The settlement incorporates different triggers for each program and establishes a tracking system for Peak Time Rebate payments to identify any possible instances of an overlap in payments between the two programs. The settlement recognizes the SDG&E General Rate Case Phase 2 proceeding as the place to adjust incentives and decide cost allocation issues.[218] This settlement, described in Exhibit 131, is adopted by this decision.

18.3. Discussion of Dual Program Participation

Current Commission policy supports increasing the amount of cost effective demand response available and the flexibility of demand response programs to reduce electricity load during declared energy emergencies or at times of high electricity prices. It is reasonable to evaluate the possibility of concurrent participation in dual programs to determine whether it has the

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217 Opening Brief of Southern California Edison Company (U 338-E), January 28, 2009, p. 14.

218 Exhibit 131, January 7, 2009, Agreement Regarding Interaction of Summer Saver and Peak Time Rebate Programs.

potential to expand the current level of demand response while minimizing ratepayer costs.

Participation in more than one demand response program may provide flexibility to customers and expand their ability to respond to the varying conditions that trigger demand response. However, guidelines must be adopted that prevent double payment for a single load drop when that load drop is made by a customer enrolled in two programs with simultaneously called events.

These guidelines will also prevent double counting of load drop for participants in multiple programs, to maintain accurate load drop estimates for resource adequacy purposes. As the utilities implement dynamic pricing tariffs and further develop the CAISO's new market mechanisms, additional opportunities may emerge for dual demand response program participation. This is an appropriate time to establish guidelines to facilitate growth in demand response through dual program participation while safeguarding ratepayers from excessive or duplicative payments.

Parties agree in theory that dual program participation may further the goal of increasing both customer choice and potential for demand reductions, but many disagree on how dual program participation should be implemented. Most parties distinguish between programs which offer capacity payments and those which offer energy payments. There seems to be broad agreement among parties on the following points:

- Customers should not be allowed to participate in more than one program that offers capacity payments. No utilities permit concurrent participation in more than one program that provides capacity payments, such as the Base Interruptible Program, Capacity Bidding Program and the various air conditioner cycling programs.

- It may be reasonable to permit customers to participate in more than one program that offers energy payments, as long as a customer only receives payment through one program for a given load drop. This allows for the possibility that a customer could enroll in and be paid under two energy payment programs, as long as those programs do not have a simultaneous events or the customer receives payment under only one program if simultaneous events do occur.

- It may be reasonable to permit customers to participate concurrently in a program that offers capacity payments and a program that offers energy payments. However, in the case of simultaneous events, customers should receive payment from only one program.

Parties disagree on the following issues:

- If customers are enrolled in two programs, one of which provides energy payments and the other capacity payments, and these programs have simultaneous events, should the customer receive the payment for the energy program or the capacity program? PG&E and SCE allow Demand Bidding Program (which pays only energy incentives) customers to participate in capacity payment programs and in the case of simultaneous events customers do not receive the Demand Bidding Program energy payment. However, the recent settlement agreement discussed in Section 19, below, among DRA, SCE, and aggregators EnerNoc and AER, allows dual participation by taking the opposite approach. The settlement states that in the case of simultaneous events, customers who participate in these aggregator contracts (which are capacity payment programs) and the Demand Bidding Program would receive Demand Bidding Program energy payments, but their load drop would not be counted towards the aggregator's load reductions.

- Which programs should be considered energy payment programs, and which programs should be considered capacity payment programs? For some programs, the classification is fairly clear: all parties agree that the air conditioner cycling programs, and the Base Interruptible Program, which offer customers monthly incentives based on a willingness to reduce load if called upon, offer only capacity payments. However, PG&E and SCE consider Critical Peak Pricing programs, which are dynamic rate programs, to be capacity payment programs, whereas SDG&E and the various aggregators suggest that Critical Peak Pricing should be considered an energy payment program. As a result, PG&E and SCE do not allow dual participation in Critical Peak Pricing and programs such as air conditioner cycling, the Base Interruptible Program, or the Capacity Bidding Program, whereas SDG&E does allow Critical Peak Pricing customers to participate in capacity payment programs.

- Should customers be allowed to participate concurrently in both a utility-administered program and one run by an aggregator? PG&E and SCE do not allow customers enrolled in their programs to also participate in the aggregator contracts, with the exception of the recent SCE settlement agreement mentioned above. SDG&E allows dual participation of customers on Capacity Bidding Program, a program in which the all customers are enrolled through aggregators, and in certain other programs.

One last concern raised by the possibility of concurrent customer participation in dual demand response programs is that customers could attempt to "game" the system if the energy use charges associated with some events are less than the penalties associated with failure to perform under another program; this could be the case for Critical Peak Pricing when combined with the Base Interruptible Program. A customer could, with careful planning and a lot of luck, avoid reducing demand to the Firm Service Level during a simultaneous Base Interruptible Program/Critical Peak Pricing event and avoid the usual penalty.

18.3.1. Possibility of Negative Demand Charges

In comments on the proposed decision, SCE states that dual participation in BIP and CPP would result in a negative demand charge of approximately $13.74 per kilowatt, as shown in the table below, excerpted from SCE's opening comments on the PD filed July 20, 2009:

Table II-1
Illustrative Overpayment For Dual Participation in CPP and BIP

1. TOU-8 (Secondary), summer, on-peak generation demand charge	$18.74/maximum on-peak kW
2. TOU-BIP (Secondary), summer, on-peak credit	($19.74)/average on-peak kW
3. TOU-8-CPP (Secondary), summer, on-peak generation demand credit	($12.47)/maximum on-peak kW
Net charge (Lines 1, 2, and 3)	Approx. ($13.47)/kW[7]

However, the bill impacts depicted by SCE would only occur under specific circumstances. First, the BIP on-peak credit (Line 2 in the table above) also depends on the customers' firm service level. This credit is determined by multiplying the $19.74 by the customer's average on-peak demand minus the customer's firm service level, whereas the CPP credit and the on-peak generation demand charge are based on a customer's peak demand (including the customer's firm service level). Hence, a customer would face a negative per kilowatt demand charge of $13.47 only if its maximum on-peak demand were equal to its average peak demand (e.g., a customer with a load factor of 100%, or a flat load profile) and it had a firm service level of zero. There are likely to be very few, if any, customers in this situation.

In addition, SCE's table does not include the facilities-related demand charge of $11.60, which is assessed on a customer's maximum demand, regardless of period. Since any customer's maximum demand will either occur during the on-peak period, or be greater than the customer's maximum demand during the on-peak period, the maximum $13.74 per kilowatt demand credit will be reduced by $11.60 to $1.87. When the generation and facilities demand charges faced by the customer are considered together, the likelihood that the total demand charge will be negative is extremely unlikely, and would only occur if a customer has both a flat load profile and a firm service level of zero. In addition, customers also face additional charges which may include monthly meter charge, the per kWh energy charges (of up to $1.36 per kWh during CPP events), and other miscellaneous charges.

SCE is correct in that dually-enrolled BIP and CPP customers would receive large reductions in their bills, but whether a customer sees a negative demand charge depends on the firm service level and load characteristics of the customer, and the chances of this occurring are further reduced when the facilities demand charge is considered.

18.4. Requirements for Dual Program Participation

We conclude that it is reasonable and consistent with the Commission's policy of encouraging cost effective demand response activities to allow customers to participate concurrently in two demand response activities and programs, as long as duplicative payments for a single instance of load drop can be avoided. One way to accomplish this that is supported by most parties to this proceeding is to allow customers to participate concurrently in one program that provides an energy payment and one that provides a capacity payment. This also appears to be a relatively simple way to categorize programs to maintain consistent rules across the different utilities' service territories. We direct that the utilities develop rules and procedures allowing customers in two programs, one providing capacity payments and one providing energy payments. In addition, we direct that these rules will prohibit participation in two day-ahead programs or two day-of programs.

Critical Peak Pricing has elements of both a capacity payment program and an energy payment program. Critical Peak Pricing acts as an energy payment program to the extent that a customer's bill savings is determined by the amount by which the customer reduces its peak electricity consumption. At the same time, Critical Peak Pricing acts as a capacity program in that it rewards a customer all the time for its willingness and readiness to reduce demand when an event is called. In order to further our goal of increasing the amount of demand response available at times of peak load, it is reasonable to consider Critical Peak Pricing to be an energy payment program. It is not consistent with Commission priorities to limit customers' ability to reduce peak demand simply because it *might* result in some customer overpayment in certain rare circumstances. To the extent that this policy may create apparent conflicts with existing or proposed rate designs for certain combinations of programs, procedures exist for examining and, if appropriate, modifying the rate designs to address those issues. For the purpose of demand response dual participation rules in 2009-2011, we will consider Critical Peak Pricing to be an energy payment program in which customers may participate concurrently with capacity payment programs such as the Capacity Bidding Program.

These decisions introduce a small possibility of double payment for load drop under particular circumstances, and rules are necessary to minimize this undesirable outcome. Towards that end, we require that in the case of simultaneous or overlapping events called in two programs, a single customer enrolled in two programs will receive payment only under the capacity program, not for the simultaneous event for the energy program. Customers enrolled in

Critical Peak Pricing and a capacity payment program will be charged the higher Critical Peak Pricing rates during called events, and will receive payment for the event under the capacity program. In all dual participation situations, the capacity payment program will be credited with participants' load drop during any called events. This is consistent with the principle of a capacity program, under which customers are rewarded for their constant readiness to reduce load. In addition, the customer's baseline for both programs will be calculated based on days in which no events are called in either program. These rules will be applied statewide in order ensure that customers throughout the state are treated similarly and fairly. These rules will also apply regardless of whether the customer is enrolled in a utility-administered program or one administered by a third-party aggregator. To implement these rules, each utility is ordered to file a Tier 2 advice letter within 90 days of this decision, specifying which programs it considers to be energy programs and capacity payment programs, and describing its plan for educating customers on the interactions of various programs to ensure that participants can make informed choices about program enrollment. This Tier 2 advice letter will also state the specific permissible combinations of programs, with Critical Peak Pricing programs generally compatible with programs offering capacity payments. We intend for these new rules to go into effect on January 1, 2010, or upon Energy Division approval of the advice letters, whichever is later.

In comments on the proposed decision, SCE identified rate design concerns created by allowing customers to participate in both Critical Peak Pricing and capacity based programs such as the Base Interruptible Program. If a utility believes that there are rate design issues that should be addressed prior to implementing our adopted dual participation policy, a utility may delay implementation of these new rules to as late as May 1, 2010. Any plans to delay implementation beyond January 1, 2010 must be explained in the Tier 2 advice letter on dual participation described above. We expect that allowing implementation of these rules in January 2010, with the possibility of a delay to as late as May 1, 2010, will provide utilities with sufficient time to determine any challenges they may face in tracking and billing or crediting customers enrolled concurrently in more than one demand response activity, and find ways to accommodate those customers' choices consistent with these new requirements.

We recognize that some contracts that have already been approved by this Commission, or are being approved in this decision, have concurrent program participation requirements that are not consistent with the rules adopted here. We do not require the alteration of existing contracts to make them consistent with these rules; however, we do encourage utilities and aggregators to consider these rules when negotiating new contracts or modifying contracts that have been previously approved.

While we share parties' concerns over the possibility of customer gaming, it is unlikely that many customers have the ability and the desire to enroll in two programs with the intention of underperforming in one while making up for the program penalties through participation in another. Simultaneous events in two programs such as the Base Interruptible Program and Critical Peak Pricing are rare, and that the total amount of money saved by a customer even if such an event occurs in unlikely to be large. Knowing this, it is reasonable to adopt the concurrent program participation rules described above. Still we expect utilities to be vigilant in watching for possible instances of gaming through 2010 and 2011, especially as some programs increase in size.

If necessary, the rules established here can be reassessed as programs develop and utilities gain experience with new programs and program interactions. We will reevaluate these rules to determine their effectiveness in promoting program participation, increasing available demand response load reductions, and avoiding instances of duplicative payments and gaming.

18.5. PG&E Partial Standby Metering Customers

CDRC proposes that customers on PG&E's partial standby metering rates should be able to participate in certain demand response activities for the load they purchase from PG&E. Partial standby customers can currently participate in the PG&E Demand Bidding Program, Business Energy Coalition, and Base Interruptible Program. PG&E notes that it has completed system modifications that allow the company to include partial standby customers in several other programs, including its Aggregator Managed Portfolio, Capacity Bidding Program, Critical Peak Pricing, and PeakChoice Program, and so does not oppose this request. It is reasonable to allow partial standby customers to participate in these demand response programs for the load they purchase from PG&E, and we approve this request.

19. SCE Contracts with Demand Response Aggregators

19.1. Procedural Background

In A.08-06-001, SCE asks approval of four contracts with four different demand response aggregators, Energy Curtailment Specialists (ECS), EnerNOC, AER, and ECI. The Commission previously rejected contracts with these providers in D.08-03-017, in which four other aggregator contracts were adopted. That decision suggested that SCE could renegotiate the rejected contracts and request approval of the modified contracts in this application, which SCE subsequently did.

All four contracts originally included provisions that they would terminate if not approved by the Commission by February 28, 2009. Three of the aggregators amended their contracts to extend the approval deadline to June 30, 2009; ECI did not approve an extension, and allowed its contract to terminate under this provision. The ECI contract is therefore no longer under consideration in this proceeding.

On February 23, 2009, SCE filed a motion for approval of a settlement agreement the contracts between SCE and EnerNOC, and between SCE and AER. The Settlement Agreement is between DRA, SCE, and these two contractors; the redacted public version of this settlement agreements are included with this decision as Attachment A.[219] ECS, which was not a party to this settlement, filed comments on March 25, 2009, opposing the settlement unless several modifications in the settlement were also applied to ECS's own contract with SCE. Both DRA and SCE filed comments opposing the request to apply some (but not all) modifications made to the AER and EnerNOC contracts to the ECS contract.

On April 17, 2009, SCE and ECS filed a joint motion to withdraw the ECS contract from consideration in this proceeding. No parties filed responses to this motion, which remains unopposed. The motion to withdraw the ECS contract is

[219] The Settlement Agreement is Exhibit A of Joint Motion of Division of Ratepayer Advocates, Southern California Edison Company, EnerNOC, Inc., and Alternative Energy Resources, Inc., for Adoption of Settlement Agreement, filed February 18, 2009.

granted, and only the EnerNOC and AER contracts as modified in the February 23, 2009, proposed settlement remain at issue in this proceeding.

19.2. DRA Analysis of the Proposed Contracts

The only party in this proceeding that provided detailed independent analysis of these proposed aggregator contracts is DRA. Based on its analysis, DRA asserts that the four aggregator contracts as originally proposed in SCE's application are substantially similar to the contracts rejected by the Commission in D.08-03-017. DRA argues that these contracts are poorly structured, not cost effective, and do not include substantially better ratepayer protections than the four aggregator contracts that the Commission rejected in D.08-03-017.[220] DRA also states that the payment and penalty history of the current SCE contracts shows that in the months an event is not called, the aggregator is paid for capacity it has not shown it can deliver,[221] and that the penalty structure and the basic capacity and energy payment structure in the proposed contracts are identical to the ones in the existing contracts, as well as the rejected contracts.[222] DRA also states that the Commission should direct the utilities to require that all proposed third-party contracts contain provisions that adjust capacity payments based on an aggregator's most recent performance in a Test, Re-Test, or dispatch event to ensure that payments during the ramp-up period and beyond are commensurate with actual performance.[223] DRA alleges that the four contracts

[220] DRA, Exhibit 316 at 8.

[221] DRA, Exhibit 316 at 10.

[222] DRA, Exhibit 316 at 12.

[223] DRA, Opening Brief at 23.

as originally submitted have significant potential to overpay aggregators for demand reductions rarely if ever delivered.

19.3. Discussion

In order to adopt the settlement agreement, it is necessary to find that "the settlement is reasonable in light of the whole record, consistent with law, and in the public interest."[224] The settlement of the EnerNOC and AER contracts in this case is essentially uncontested. The only objection to the settlement was from ECS, which objected to certain provisions unless they could also be applied to the ECS contract. Because the ECS contract has been withdrawn, this issue is no longer relevant. To determine the reasonableness of this uncontested settlement, we analyze it within the context of the initial litigation positions of the parties.

We find the settlement reasonable in light of the whole record, consist with the law, and in the public interest. The terms of the contracts under the proposed settlement are significantly improved from the originally proposed terms: they are likely to be less susceptible to gaming by the contractors, and more likely to deliver the promised capacity when called. The prices to be paid by SCE have also been lowered.

In its application, SCE initially estimated the benefit to cost ratios of these two contracts to be close to or exceeding 1.0, depending on the amount of transmission and distribution benefits included in the analysis.

By lowering the costs to be paid by SCE while not reducing the benefits under the contracts, the modifications made in the settlement are likely to improve the benefit to cost ratios of these two contracts, which were already

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[224] Commission Rules of Practice and Procedure, Rule 12.1(d).

close to (or exceeding) one. Because the settlement effectively addresses the gaming concerns of DRA and is likely to improve the contracts' cost effectiveness, it is reasonable to approve the settlement, and approve the contracts between SCE and AER, and SCE and EnerNOC as modified under that settlement. We also approve the associated funding for these two contracts, totaling $38,773,160.

We note that the baseline and multi-program participation rules agreed upon in these contracts are not consistent with the rules adopted for other programs elsewhere in this decision. We adopt the settlement and approve the contracts as proposed, but in the future we expect parties to comply with the principles for baseline calculation and the multi-program participation rules established in this decision.

20. BluePoint Proposal: Backup Generation

In its initial comments[225] on the utilities' applications, BluePoint introduces the concept of "backup generation with enhanced controls" (BWEC). According to BluePoint, BWEC involves the use of proprietary enabling technology to harness a certain type of mandated test generation from some backup generators. In its testimony, BluePoint asserts that its BWEC technology meters, monitors, and dispatches backup generation from meter tests that is currently wasted, and allows this generation to be dispatched from a central location, making that energy available during peak demand.[226] By enabling the use of this energy, and dispatching it at peak times, BluePoint argues that properly

[225] Response of BluePoint Energy, filed July 9, 2008, in A.08-06-001 et al. (BluePoint July response).

[226] BluePoint July Response, pp. 2-3.

configured backup generation such as BWEC has characteristics of demand response in that it can decrease net load on demand, allowing it to function as participating load, and can respond to price signals, scarcity pricing, and variability of production by renewable energy sources.[227] BluePoint further advocates for the Commission to allow cost effective backup generation resources to receive technical assistance and technology incentives funding as a demand response resource. Specifically, BluePoint considers backup generation to be a demand-side resource because it is typically owned by a customer, not a utility or other load-serving entity, and is operated for that customer's own benefit.[228]

BluePoint argues that backup generation, as a demand-side resource that has the characteristics of demand response, should be considered a valid demand response option that is eligible to receive demand response funding, including Technical Assistance and Technology Incentives funds. BluePoint further argues that the technology used to reduce load is less important than the load reduction itself, and that when load curtailment is present with behind the meter generation that uses clean and efficient use of fuels for load reductions, as it contends is the case for BWEC, it is reasonable to make such activities eligible for TA/TI funds.

BluePoint further contends that BWEC is environmentally friendly, both because it does not increase greenhouse gases or other harmful emissions if the generators use renewable energy or otherwise minimize emissions, but also

[227] BluePoint Opening Brief, filed January 28, 2009, p. 3 (BluePoint Reply Brief).

[228] BluePoint Opening Brief, p. 3.

because BWEC captures energy from required generator tests that would be run in the absence of BWEC, converting wasted energy into a useable resource.

All three utilities and TURN oppose the BluePoint proposal. TURN asserts that BWEC is not a demand response proposal, but a proposal that would use demand response funds to subsidize generation.[229] TURN also disputes the contention by BluePoint that BWEC is "green" or environmentally friendly, noting that an early study of demand response suggested that demand response programs could actually increase net emissions by encouraging the use of diesel-fueled backup generators.[230] In addition, TURN disputes the assumptions made by BluePoint about the number of hours in which BWEC from generator tests could be available up to 250 hours per year, saying that a much lower number is more likely.[231] TURN suggests that the Commission require the collection of this information as part of the 2009-2011 program evaluation activities.[232]

SDG&E asserts that BluePoint failed to meet its burden of proof that the BWEC proposal addresses the Commission's concerns about backup generation, and that BluePoint has failed to meet this burden through its testimony in this proceeding.[233] SDG&E states that if the Commission believes that BluePoint has met its burden of proof, BWEC related projects that meet all other program requirements could be eligible to receive Technical Assistance and Technology

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229 Exhibit 421, p. 7.

230 TURN Opening Brief, p. 13.

231 Exhibit 421, p. 7.

232 Ibid.

233 SDG&E Reply Brief, p. 73 and Exhibit 122, p. 8. SDG&E does not specifically describe the Commission concerns about backup generation to which it refers.

Incentives funding. PG&E notes that the Commission has rejected previous proposals to use demand response funds on backup generation on the grounds that backup generation is not true demand response, and encourages the Commission to reject the BluePoint proposal in this proceeding on the same basis.

20.1. Discussion

In at least two previous decisions, the Commission has stated it does not consider backup generation to be a type of demand response, and has rejected requests to use demand response funds to support backup generation. In D.06-11-049, the Commission considered and rejected a PG&E proposal to add emissions control technologies to diesel engines. The Commission stated that, "… Our objective in funding demand response programs is to reduce system demand, not to substitute system electricity with electricity generated by off-grid facilities. We previously found in D.05-01-056 that backup generation is not a true demand response resource."[234] Similarly, in D.05-01-056, the Commission found that backup generation is not a demand response resource, and expressly stated that, "… in future years, [backup generation demand response programs] should not be funded through the demand response program budgets."[235] The Commission has also expressed concern that backup generation, such as diesel generators, contradicts the Energy Action Plan's loading order preference and represents one of the dirtiest generation sources available.[236]

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[234] D.06-11-049, p. 58.

[235] Ibid.

[236] Ibid.

BluePoint has not provided sufficient new information to persuade us that backup generation actually provides demand response by reducing load, rather than substituting energy from a different source. As TURN notes, we do not have information on the frequency with which participants in demand response programs use backup generation to meet their energy needs when called upon to reduce load as part of a demand response program, and it is possible that this is occurring on a regular basis. The issues here are not whether this should happen or how often it happens, but whether the Commission should encourage this substitution by facilitating the substitution with demand response funding. As a policy matter, we have already found that subsidizing backup generation with demand response funds is not appropriate; we prefer to reserve these funds for activities that reduce total energy use. Consistent with this policy, we are not persuaded that it is appropriate to use demand response funds on backup generation, and we will not adopt the BluePoint proposal to recognize backup generation as demand response nor use technical assistance and technology incentives information for BWEC.

The Commission has never fully evaluated the extent to which participants in current demand response activities may be using backup generation to meet their demand response commitments. Gathering information on this issue would enable us to gauge whether demand response load impacts represent energy that is truly saved or shifted to off peak hours, or whether it is merely supplied by unregulated sources, and whether demand response has an inadvertent negative environmental impact. While we decline to require utilities to gather information from participants in demand response activities during 2009-2011, we encourage the Demand Response Measurement and Evaluation Committee to study this issue.

21. Permanent Load Shifting

The phrase "permanent load shifting" refers to the shifting of energy usage by one or more customers from one-time period to another on a recurring basis. Permanent load shifting often involves storing electricity produced during off peak hours and then using the stored energy to support load during periods when peak energy use is typically high. Examples of permanent load shifting technologies include battery storage and thermal energy storage. Thermal energy storage draws electricity during off-peak hours, which it stores in the form of thermal energy in ice, chilled water or a eutectic salt solution. That stored energy can be used during peak hours, generally to cool buildings without drawing additional electricity from the power grid during the day.

In D.06-11-049, the Commission noted that permanent load shifting may not fit within the definition of energy efficiency if the technology used does not reduce overall energy consumption. Similarly, permanent load shifting is not like most demand response programs in that it is not usually dispatched on a day-ahead or day-of basis, nor does it respond to short-term price fluctuations. Still, permanent load shifting, like demand response, can reduce summer peak demand and is reasonably considered in the context of demand response programs that produce a similar end result. The Commission recognizes that permanent load shifting could "reduce the likelihood of shortages during peak periods and lower system costs overall by reducing the need for peaking units."[237]

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[237] Order Adopting Changes To 2007 Utility Demand Response Programs, D.06-11-049, November 30, 2006, p. 49.

Further, in D.06-11-049, the Commission directed the utilities to pursue a Request for Proposal (RFP) and bilateral arrangements to solicit five-year commitments with third parties for permanent load shifting projects that would conserve or reduce energy during critical peak periods starting in the summer of 2007. In response to D.06-11-049 all three utilities, PG&E, SCE and SDG&E, issued RFPs and now have ongoing permanent load shifting programs through 2011. SCE has three contracts, and PG&E and SDG&E each have two contracts. SCE's and PG&E's programs use thermal energy storage technologies to create permanent load shifting.

In various filings and discussions, the utilities refer to their permanent load shifting programs as pilots. Pilot programs are generally designed to test technologies or answer questions about the uses and applications of those technologies. In the case of the permanent load shifting activities, however, it is not clear what aspects of the technologies are being tested or what questions are being explored. For this reason, we consider the permanent load shifting activities discussed in this section to be programs, not pilots. Actual pilots, including some involving permanent load shifting, are discussed in Section 11 (for most pilots) and Section 22.1 (for the Small Commercial Aggregation Pilot) of this decision.

21.1. Utility Permanent Load Shifting Proposals

The utilities' applications focus on existing rather than new permanent load shifting activities. Most existing permanent load shifting activities were approved by the Commission in previous decisions and resolutions. In order to maintain existing permanent load shifting contracts and activities, PG&E requests $138,000 for additional administrative costs related to its already-approved permanent load shifting activities;[238] SCE requests approval to carry forward $4.4 million in unspent funds approved for permanent load shifting contracts;[239] and SDG&E requests an additional $300,000 for administer its ongoing programs.[240] The only utility that proposes to go beyond its already approved permanent load shifting activities is PG&E, which asks for authority to issue an RFP in 2011 in order to ensure new permanent load shifting is in place when the utility's current permanent load shifting contracts expire on December 31, 2011.[241]

21.1.1. Party Positions and Proposals

Two parties, Ice Energy and Transphase, submitted comments on the utilities' permanent load shifting proposals. Neither of these parties oppose the continuation of existing permanent load shifting activities or argue against permanent load shifting in general; in fact, both recommend that the Commission expand the availability of permanent load shifting through the approval of additional activities and funding beyond that requested by the utilities. Their proposals are addressed in Sections 21.2 and 21.3, below.

21.1.2. Discussion on Utilities' Requests

Benefits of permanent load shifting highlighted in the record include its ability to reliably and persistently lower on peak demand,[242] to reduce carbon

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[238] PG&E Exhibit 201, Chapter 1, p. 13.

[239] SCE Exhibit 1, pp. 53-54.

[240] SDG&E Exhibit 102, p. 64.

[241] PG&E Exhibit 201, Chapter 1, p. 40.

[242] Transphase Exhibit 1025, p. 18 and p. 20.

dioxide and nitrous oxide emissions[243] to the extent fossil fuel plants are displaced during peak hours, and to utilize energy generated during off peak hours by wind resources.[244] The attributes of thermal energy storage not disputed in the record are the reliability of these technologies, which have been operational for up to 20 years,[245] and the ability to effectively measure equipment performance.[246]

Cost effectiveness results for permanent load shifting activities provided by PG&E estimate that PG&E's existing Shift and Save program is cost effective.[247] SCE does not include detailed cost effectiveness analyses of its permanent load shifting activities in these applications, presumably because the activities and funding have already been approved. Like SCE, SDG&E notes that it provided cost effectiveness analyses of its permanent load shifting activities when it requested approval of its existing permanent load shifting activities. Still, permanent load shifting has many benefits enumerated in the testimony, and the funding requested in these applications to support permanent load shifting is relatively minor and in most cases is intended to support internal administration of permanent load shifting contracts that have already been approved. Though permanent load shifting is not currently integrated with the CAISO's new markets, and does not have flexible trigger mechanisms, it does

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243 Transphase Exhibit 1025, Chapter 2, p. 31.

244 PG&E Exhibit 201, Chapter 2, p. 33.

245 References to lifetime of technologies: Transphase Exhibit 1025, pp. 21, 28, 29, 46, 75, 76, and 78.

246 Transphase Exhibit 1025, p. 72.

247 PG&E Exhibit 205 (Tables 6-4 and 6-5 in Appendix 6-A).

provide a reliable load drop at peak times, and some permanent load shifting technologies have been proven to provide benefits for years, or in some cases decades, after initial installation.

The contracts under which the utilities are providing permanent load shifting have already been approved by the Commission, and it is logical to continue these permanent load shifting activities for the terms of their existing contracts. We approve the funding requested by the utilities to maintain their existing contracts in these applications. Specifically, PG&E is authorized to spend an additional $138,000 beyond its existing funding for permanent load shifting, SDG&E is authorized to spend an additional $308,371 beyond its existing funding, and SCE is authorized to carry forward $4.4 million in unspent funding that was approved for SCE's permanent load shifting contracts.

We do not approve PG&E's proposal to issue a further permanent load shifting RFP in 2011. Many circumstances relevant to the expansion of permanent load shifting are likely to change by 2011. For example, it is likely that AMI meters and dynamic rates will be in broader use by 2011 and 2012, and the utilities are expected to be preparing their next demand response applications to cover the 2012-2014 period. In addition, it is not clear whether an RFP process will be appropriate in the future whether a permanent load shifting standard offer should be considered. It is reasonable to defer decisions on the place of permanent load shifting in future years until more information is available.

21.2. Ice Energy Proposal

Ice Energy supports the current efforts of each utility, but requests that the Commission encourage the utilities to expand the scope of permanent load shifting as a component of demand response.[248] Ice Energy supports PG&E's request to issue a new RFP on permanent load shifting in 2011, and recommends that SDG&E follow PG&E's example by issuing an additional RFP, and integrating permanent load shifting with renewable technology.[249] Ice Energy also recommends that SCE expand its current permanent load shifting activities beyond 2011. In general, Ice Energy encourages utilities to open permanent load shifting tariffs and activities to direct access customers, increase rebate levels for installation of permanent load shifting, and undertake more pilots on integrating permanent load shifting with sources of renewable energy.[250]

21.2.1. Party Positions on Ice Proposals

SDG&E characterizes Ice Energy's proposal as a "set aside," and asserts that the Ice Energy proposal would not apply neutrally to different sorts of permanent load shifting technologies, and amounts to "a request for the Commission to direct ratepayer support for 'a specific company or technology.'"[251] All three utilities assert that the Commission should not direct

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[248] Ice Energy, Inc. Exhibit 901, p. 10.

[249] Comments of Ice Energy Inc. on the Application of San Diego Gas & Electric Company for approval of Demand Response Programs, Goals and Budgets for 2009-2011, July 9, 2008, p. 2; and Comments of Ice Energy Inc. on the Application of Southern California Edison Company for approval of Demand Response Programs, Goals and Budgets for 2009-2011, July 9, 2008, p. 2.

[250] Ice Energy Exhibit 901, pp. 9-10.

[251] SDG&E Opening Brief, pp. 69-70.

the utilities to expand permanent load shifting until the existing permanent load shifting activities approved in 2007 are complete.

21.2.2. Discussion on Ice Energy Proposals

The proposals made by Ice Energy generally support expanding permanent load shifting through additional RFPs, pilot programs, and tariff changes. Few parties commented on these proposals, and SDG&E's specific comments about "set asides" do not seem to directly respond to the specifics of the proposals. Most of Ice Energy's proposals for expanding permanent load shifting are general statements of directions or principles, and are not supported by detailed implementation plans. Given this, it is not possible to evaluate the cost effectiveness or quantify the other benefits of Ice Energy's proposals. While we support the expansion of permanent load shifting, the particular strategies offered by Ice Energy are not sufficiently supported by analysis and details to evaluate here. For the same reasons that we deny the PG&E request to issue an additional RFP on permanent load shifting in 2011, we reject the Ice Energy request to require SCE and SDG&E to issue their own similar RFPs. Issues related to tariff development should be addressed in appropriate rate design proceedings.

21.3. Transphase Proposal: Thermal Energy Storage Standard Offer

Like Ice Energy, Transphase supports the continuation and expansion of permanent load shifting as a portion of the utilities' demand response portfolios. Unlike Ice Energy, Transphase does not support the RFP process used by the utilities to procure permanent load shifting in the past, and instead proposes an alternative that it hopes would encourage customers to purchase permanent load shifting systems directly. Transphase proposes a Thermal Energy Storage

Standard Offer that would provide incentive payments to any utility customer that purchases a Thermal Energy Storage system.[252]

Under the Standard Offer proposal described by Transphase, each utility would offer a payment of $800 per kilowatt to the vendor of an installed Thermal Energy Storage system, in addition to $300 per kilowatt to be paid from the customer to the vendor.[253] In addition, the company proposes a $200 per kilowatt incentive for each of the first three years after the technology is installed, contingent on the installed system providing verified savings at an agreed-upon level.[254] Combined, the $800 per kilowatt installation payment and three years of $200 per kilowatt incentive payments total $1,400 per kilowatt. Based on current time of use rates in each service territory, Transphase estimates a one to three year payback for customers;[255] Transphase asserted at hearings that, in order for the Standard Offer to be successful at encouraging the level of expansion of Thermal Energy Storage that Transphase hopes for, the Standard Offer "would… give the customer a tremendous payback."[256]

Transphase estimates that under the standard offer new Thermal Energy Storage projects would ramp up over the next several years, and could provide a total of 65 megawatts of peak demand reduction statewide by 2011. The company used the 1996 California Energy Commission report, "Source Energy and Environmental Impacts of Thermal Energy Storage," which estimated

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[252] Transphase Sponsored Testimony, Exhibit A, p. 7.

[253] Transcript from hearing, Day 5, Volume 5, p. 651.

[254] Opening Brief, p. 41.

[255] Transphase Exhibit 1025, p. 12.

2,500 megawatts of Thermal Energy Storage were available in California by 2005, to estimate 65 megawatts of load could be shifted from thermal energy storage by 2011.[257] If the 65 megawatts goal were reached by 2011, the funding needed to support the standard offer, including administrative costs for the utilities, would be approximately $111 million.[258]

If the Commission does not adopt the Thermal Energy Storage Standard Offer, Transphase proposes that customers with Thermal Energy Storage be eligible for funding through the technical incentives programs if they also participate in the Capacity Bidding Program or the Base Interruptible Program. Like the Thermal Energy Storage Standard Offer, this Transphase proposal focuses specifically on Thermal Energy Storage technologies rather than all forms of permanent load shifting.

21.3.1. Party Positions on Transphase Proposals

The utilities focus on two problems with the standard offer proposal made by Transphase. First, they and TURN argue that the $1,400 total incentive amount proposed in this standard offer is simply too high. The utilities argue that the proposed standard offer would not ensure procurement at the lowest possible cost, because there are a variety of technologies even within the thermal energy storage industry with different features and capital costs, many of which

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[256] RT Day 5, p. 678.
[257] Transphase Exhibit 1025, p. 671.

[258] Transphase Exhibit 1025, p. 9.

cost less than $1,400 per kilowatt.[259] Transphase estimates the costs of various types of Thermal Energy Storage technologies at between $200 and $800 per kilowatt, though costs may vary more widely.[260] Transphase proposes an initial incentive of $800 per kilowatt, equal to the maximum estimated cost of the technology, with an opportunity for additional payments of up to $600. Based on this comparison, the utilities and TURN both assert the proposed standard offer of $1,400 per kilowatt is not competitively priced. PG&E further argues that vendors will propose different price levels through an RFP process, possibly enabling utilities to procure permanent load shifting at a lower price.[261] PG&E acknowledged in hearings that a standard offer would allow a customer to solicit competitive offers from a variety of vendors; however, PG&E argued that a competitive solicitation will yield a lower price.[262] The utilities jointly argue that the proposed standard offer would not ensure procurement at the lowest possible cost, because there are a variety of technologies even within the thermal energy storage industry with different features and capital costs, some of which cost less than the $1,400 per kilowatt. However, PG&E also acknowledges that a standard offer would allow customers to solicit competitive offers from a variety of vendors.[263]

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[259] Joint Opening Brief of Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company on Proposal of Transphase, February 4, 2009.

[260] Transphase Exhibit 1025, p. 75.

[261] RT Volume 4, p. 518.

[262] RT Volume 4, p. 518.

[263] RT Volume 4, p. 518.

The utilities also note that the cost effectiveness used by Transphase does not conform to the Consensus Framework used by the utilities and accepted in this decision for estimating cost effectiveness of programs, and makes several other non-standard choices in its analysis. [264] Because of these differences, the utilities argue that it is not possible to know if Transphase's standard offer proposal is actually cost effective.

21.3.2. Discussion of Transphase Thermal Energy Storage Standard Offer Proposal

At this point, it is not clear whether the standard offer proposal as described by Transphase is cost effective or in the public interest. On the one hand, PG&E found its own ongoing permanent load shifting pilot (Shift and Save) to be cost effective, despite the fact that the program has an incentive of up to $1,950 per kilowatt, which is higher than the $1,400 per kilowatt proposed by Transphase.[265] Ice Energy also argues that its units are cost effective because they deliver load shifting over the 15-year life of the equipment, helping to offset the initial cost.[266] These points suggest that even if the proposed $1,400 per kilowatt standard offer is unnecessarily high, a program with this incentive level could still be cost effective. In order to be in the public interest, however, cost effectiveness of a program may not be enough. For this proposed expenditure of ratepayer money, the incentive should be set at the lowest level possible that will

[264] Joint Opening Brief of Pacific Gas & Electric Company, San Diego Gas & Electric Company and Southern California Edison Company on Proposal of Transphase, February 4, 2009, pp. 8-10.

[265] PG&E Amended Testimony, Exhibit 205, Appendix 6A, p. 3.

[266] Ice Energy, Inc. Exhibit 902, p. 10.

stimulate investment in the technology. If a standard offer is set too high, the utilities assert that the availability of the incentive payment could insulate permanent load shifting providers from competition with other technologies with a result that is not be in the best interest of ratepayers.

In the case of permanent load shifting, as in many demand response activities, it is not always clear what is the lowest incentive that will be effective in motivating participation or stimulating investment, and this complicates the review of many activities. In this proceeding, for example, some parties argue that incentive levels on some programs are unnecessarily high, while other parties argue that they may be too low to attract continuing participation.

By Transphase's own estimate, the $800 initial payment to a vendor in many cases will cover (or more than cover) the cost of the equipment installation, meaning that many Thermal Energy Storage providers will receive more from the incentive payment than they would charge a private customer for the same system. Transphase further proposes that the customer will pay the Thermal Energy Storage vendor an additional $300 beyond the $800 utility incentive payment, meaning that the vendor could receive up to $300 more than the installed cost of the system itself. Beyond this, the customer and/or vendor would be eligible to receive an additional $600 over three years if the system functions as intended, beyond any savings the customer would accrue from shifting its load to an off peak time. It would not be correct to describe the benefits to the customer as a return on the customer's investment, because the much of the cost of the system installation would be paid by the utility incentive (and therefore, the ratepayers). A standard offer set at a level higher than needed to encourage investment in Permanent Load Shifting would represent a transfer of funds from ratepayers to Permanent Load Shifting vendors and purchasers.

More investigation of the costs and benefits of different mechanisms for supporting Permanent Load Shifting is warranted before the investment of ratepayer money supporting Permanent Load Shifting is expanded. Setting the maximum payment too high could encourage Thermal Energy Storage vendors to overcharge for their systems, which would not be in the public interest. In the case of the Transphase proposal, a comparison of the incentive amount with objective measures such as the cost of the initial investment in Thermal Energy Storage equipment makes a compelling case that the incentive may be too high.

The RFP process conducted by the utilities in 2007 did not result in rapid installation of permanent load shifting projects in time for the summer of 2007 or in subsequent years. For example, PG&E proposed 3.9 megawatts of demand response for its permanent load shifting programs during the time period covered by the permanent load shifting contracts, but as of January 2009, only 40 kilowatts were installed and operational.[267] Given these lower-than-expected results, it is possible that, as Transphase argues, a standard offer will promote competition at the customer level that will result in operational permanent load shifting sooner than if the utilities go through an RFP process. In addition, a standard offer would enable customers to choose from any vendor that offers thermal energy storage technologies, rather than from the one to three vendors that the utility selects through an RFP, and having more options to choose the technology and vendor that best suits the needs of their facility may encourage more customers to participate in permanent load shifting.

Unfortunately, no party to this proceeding proposed an alternative (lower) standard offer, and the record in this case does not contain sufficient information to determine an appropriate or optimum level of incentives for a Thermal Energy Storage-specific or a more general permanent load shifting standard offer, or to determine if any incentive for Permanent Load Shifting is necessary or appropriate.

Transphase argues in comments on the proposed decision that Sections 454.5 and 454.55 of the California Public Utilities Code require the Commission to meet its unmet resource needs through all forms of energy efficiency and demand reduction resources that are cost effective, reliable, and feasible. Transphase appears to interpret this to mean that if any demand reduction proposal is cost effective as proposed, as it argues that its standard offer proposal may be, the Commission is obligated to adopt the proposal, regardless of the proposal's cost or other implications. This logic is flawed in several ways. First, Section 454.5 directs utilities in the development of their overall procurement plans, and does not directly address Commission approval of specific resources proposals. The provisions cited by Transphase require development of energy efficiency and demand reduction strategies and technologies more broadly, rather than the adoption of every specific proposal for increasing demand response. In addition, this section states that adopted resources must be cost effective, reliable, and feasible, and allows for the rejection of proposals that do not meet all three criteria. In this case, it is not clear that the Transphase proposal is cost effective.

As discussed above, the Commission is already pursuing permanent load shifting activities through a Commission-ordered RFP process and resulting contracts for Permanent Load Shifting installations. This decision orders further

[267] RT 4, p. 498.

study of possible strategies for increasing the availability of Permanent Load Shifting in the future. This is consistent both with the provisions of the public utilities code and with the Commission's responsibility to spend ratepayer funding effectively and efficiently.

Based on information provided by parties in this proceeding we do not have enough information to make decide whether a RFP process to solicit contracts with third parties or a standard offer eligible to all types of permanent load shifting vendors is the best answer going forward for permanent load shifting. Additionally, no parties addressed whether a standard offer could be effective for all types of permanent load shifting or if it would need to be limited to thermal energy storage. Because Thermal Energy Storage and Permanent Load Shifting appear promising, we order the utilities to work with parties to examine ways of expanding the availability of permanent load shifting. A standard offer proposal that could apply generally to any permanent load shifting technologies including, but possibly not limited to, thermal energy storage, should be considered in this study. This study should also consider other ways of encouraging permanent load shifting, including modifications to time of use rates or another RFP process. The utilities should prepare and serve on the service list for this proceeding a report exploring the possibility of a standard offer program. This report should contain a summary of permanent load shifting standard offers available throughout the United States, as well as an evaluation of what incentive payment would be appropriate for a future standard offer. This report shall be served on the most recent service list for this proceeding, and provided to the director of the Commission's Energy Division not later than December 1, 2010. The utilities could then be directed to seek authorization to implement either a general permanent load shifting or Thermal

Energy Storage standard offer programs, additional permanent load shifting RFPs, or other recommended strategies, as part of their 2012-2014 applications, or utilities could revise their rate schedules in an appropriate proceeding. This report shall inform proposals to expand the use of permanent load shifting in the 2012-2014 applications.

22. SF Community Power Issues

22.1. Small Commercial Aggregation Pilot

22.1.1. Pilot Background

In D.06-03-024, the Commission adopted a settlement that included approval of the Small Commercial Aggregation Pilot. The Settlement authorized SF Power to receive $500,000 in funds to cover marketing and expenses for enrolling small and medium commercial customers in the San Francisco Bay Area in the Demand Reserves Partnership Program.[268] The original goal of the Small Commercial Aggregation Pilot was to shift 2 megawatts of load by the end of 2008. In D.06-11-049, SF Power was authorized to increase participation for the program to 5 megawatts of load reduction; this decision did not authorize an increase in the pilot's budget. Under this pilot, SF Power enrolled small and medium commercial customers into the Capacity Bidding Program. Based on a single 2008 test event conducted by PG&E, participants in the SCAP achieved a load reduction of approximately 1.4 megawatts.[269] In A.08-06-003, PG&E proposed to discontinue the Small Commercial Aggregation Pilot on

[268] D.06-03-024, Decision Adopting Settlement of the IOUs Applications for Approval of Demand Response Programs for 2006-2008, March 15, 2006, p. 14.

[269] Settlement Agreement Between Pacific Gas and Electric Company and San Francisco Community Power, March 25, 2009, pp. 1-2.

December 31, 2008. At the same time, the utility proposed its own Small Customer Load Aggregation Pilot, discussed in Section 11 above.

22.1.2. SF Power Litigation Position on Small Commercial Aggregation Pilot

SF Power protested the PG&E application on September 29, 2008, and filed written testimony on November 24, 2008. In its protest and its testimony, SF Power asserted that PG&E had not appropriately supported the Small Commercial Aggregation Pilot as ordered by the Commission in D.06-03-024 and D.06-11-049. Specifically, SF Power alleged that a quarter of the customers enrolled in the Small Commercial Aggregation Pilot by SF Power in 2006-2008 had not received meters from PG&E and so were unable to participate in the Small Commercial Aggregation Pilot. SF Power argued that the pilot should not be discontinued because PG&E's lack of support had kept the pilot from meeting its potential. The organization argued that despite this fact, depending on the baseline used, customers met the megawatt goals for the pilot during the one event that was called.[270] In particular, SF Power argued that it was not able to fully investigate demand response issues related to small load aggregation because all meters were not timely installed and activated. To remedy its past behavior and allow the Small Commercial Aggregation Pilot an opportunity to complete its work, SF Power argued that PG&E should not be allowed to discontinue the Small Commercial Aggregation Pilot, and should be required to provide Smart Meters by April 1, 2009 to all customers that had been enrolled in the Small Commercial Aggregation Pilot prior to January 1, 2009. SF Power also

[270] SP Power Exhibit 801, p. 17.

requested that the utility provide the organization with real-time data to make program adjustments.[271]

As an alternative to PG&E's proposal for a new Small Commercial Load Aggregation Pilot, SF Power proposed that the Commission should authorize $675,000 for SF Power to extend the Small Commercial Aggregation Pilot, and should authorize it to supplement or replace PG&E's proposal for a new Small Commercial Load Aggregation Pilot.[272] SF Power would use the funds for recruitment, customer care, enabling technology, and analysis of participants' usage, and proposed that results of the Small Commercial Aggregation Pilot could be available by 2010 (in contrast to 2011 for results of the PG&E proposed pilot).[273]

22.1.3. PG&E Litigation Position on Small Commercial Aggregation Pilot

In response to SF Power's claims about the Small Commercial Aggregation Pilot, PG&E asserted that it met its obligations to support the Small Commercial Aggregation Pilot under the decisions adopting and modifying the pilot. PG&E further contended that despite this support, the Small Commercial Aggregation Pilot was unsuccessful in that it did not meet its goals and was not cost effective. PG&E acknowledged that it did not install any additional meters after September 2008, noting that the pilot was scheduled to end in December 2008, and stating that meters installed after September 2008 were unlikely to be available to provide load reduction during an event called in the approved term

[271] SP Power Exhibit 801, pp. 17-20.

[272] SP Power Exhibit 801, p. 23.

[273] SP Power Exhibit, p. 24.

of the pilot.[274] The utility recommended that the Commission deny SF Power's request for installation of AMI meters in early 2009 because it would require the utility to revise its current AMI meter installation schedule.[275]

PG&E also argued that SF Power's proposal to extend the Small Commercial Aggregation Pilot instead of approving PG&E's Small Customer Aggregation Pilot should not be approved because the two pilots are not comparable. Specifically, PG&E argued that the PG&E pilot focuses on automated approaches that leverage AMI and enabling technologies whereas the Small Commercial Aggregation Pilot focuses on non-automated approach.[276]

22.1.4. Proposed Settlement Agreement on Small Commercial Aggregation Pilot

SF Power filed Case (C.) 08-10-015 on October 23, 2008. In that complaint, SF Power alleged that PG&E violated Commission orders by failing to adequately support the Small Commercial Aggregation Pilot. Both parties attended a Commission sponsored mediation of that case on March 10, 2009. At that mediation, parties agreed on a possible approach to resolve both C.08-10-015 and the issues in this proceeding related to the Small Commercial Aggregation Pilot. PG&E notified parties of a settlement conference to focus on the Small Commercial Aggregation Pilot in this proceeding, A.08-06-003. On March 25, 2009, the two parties to the Settlement Agreement filed a motion for approval of

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[274] Opening Brief of Pacific Gas and Electric Company Regarding San Francisco Community Power Proposals, February 4, 2009, p. 6.

[275] PG&E Opening Brief on SF Power, p. 9.

[276] PG&E Opening Brief on SF Power, p. 10.

the Small Commercial Aggregation Pilot Settlement Agreement dated March 25, 2009, included with this decision as Attachment B.

PG&E and SF Power state that the settlement is intended to resolve all issues raised in the SF Power complaint proceeding A.08-10-015 (which are not addressed in this decision), and the issues specific to the Small Commercial Aggregation Pilot in the demand response applications proceeding.[277] Among other terms, the proposed settlement provides the following:

- The Small Commercial Aggregation Pilot will continue through November 30, 2009.

- SF Power will not request Commission approval to extend Small Commercial Aggregation Pilot beyond November 30, 2009.

- PG&E will not install any additional meters for Small Commercial Aggregation Pilot participants beyond those in place when the settlement agreement was signed.

- PG&E will ensure that all meters already installed for Small Commercial Aggregation Pilot participants are activated by May 1, 2009.

- SF Power will withdraw its opposition to PG&E's Small Customer Load Aggregation Pilot described in PG&E's demand response application.

- PG&E will pay SF Power up to $12,500 per month from April 2009 through November 2009 for approved education and outreach activities for currently enrolled customers. The settlement contains a list of approved education and outreach

[277] Motion to adopt settlement agreement on Small Commercial Aggregation Pilot March 25, 2009.

activities. The $12,500 per month (for education and outreach to existing participants to study effective strategies for eliciting greater participation in demand response programs); this amount includes $3,000 per month that has already been authorized for SF Power's Small Commercial Aggregation Pilot program by the Commission through the 2008 Bridge Funding Decision (D.08-12-048), and is in addition to payments that SF Power and participants will receive under the Capacity Bidding Program rate schedule.[278]

- The parties agree to sign a contract that establishes a scope of work and terms of conditions, as well as appropriate education and outreach activities.

- During Capacity Bidding Program events called in 2009, PG&E will pay SF Power $16 per kilowatt for load reductions above 1.4 megawatts, up to 5 megawatts. The settlement describes the details of how the load reduction will be measured.

- The settlement further states that if no Capacity Bidding Program events or test events are called in 2009 then PG&E will call an event only for participants in the Small Commercial Aggregation Pilot to calculate a per kilowatt payment for SF Power. The maximum payment under this circumstance will be $60,000.

- SF Power will draft a report on Small Commercial Aggregation Pilot by December 31, 2009. The report will include, among other things, an overview of program performance with a description of activities used by the organization to improve customer performance. Additionally, the report will describe outreach methods and response to and success from different methods. Finally, the report will describe the practices

[278] Motion of PG&E and SF Power for Approval of Settlement Agreement, March 25, 2009, p. 6.

employed for each market segment and recommendations to maximize participation during events. The settlement includes a list of additional aspects of the program that SF Power should attempt to evaluate.

- After November 30, 2009, the parties agree that SF Power shall continue to serve as an aggregator for Small Commercial Aggregation Pilot customers under the Capacity Bidding Program. PG&E will include Small Commercial Aggregation Pilot participant load reductions in its 2009 evaluation, measurement, and verification of Capacity Bidding Program.

- There are 72 customers identified by SF Power that qualify for Capacity Bidding Program, but are not equipped with an interval meter. PG&E agrees to allow qualified customers to enroll in its AC Cycling program, SmartAC. The utility also agrees to provide SF Power with information on energy efficiency programs and rebates for which Small Commercial Aggregation Pilot participants may be eligible.

22.1.5. Discussion of Settlement Agreement

As discussed in Section 16, above, in order to adopt a proposed settlement agreement, it is necessary to find that "the settlement is reasonable in light of the whole record, consistent with law, and in the public interest."[279] No party filed any comments on or protests to the settlement. To determine the reasonableness of this uncontested settlement, we analyze it within the context of the initial litigation positions of the parties.

We find the settlement reasonable in light of the whole record, consistent with the law, and in the public interest. Small commercial customers have not traditionally been able to participate in demand response programs, and may

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279 Commission Rules of Practice and Procedure, Rule 12.1(d).

require additional education and technical assistance to participate in order to do so.[280] The Settlement Agreement proposes a total of $109,000 for education and outreach activities from January 2009 to November 2009, including the $3,000 per month already authorized in the Bridge Funding Decision.[281] The alternative of continuing the SCAP program during the 2009-2011 period as originally proposed represents over $2 million in expenses.[282] The settlement agreement provides a less expensive opportunity to gain knowledge that may help the utilities expand the demand response options available for small customers in the future.[283] Moreover, based on the Settlement Agreement, SF Power will provide PG&E with a report that will describe which marketing methods are most effective in recruiting small customers, activities to improve customer performance, whether such activities should be market segmented, and SF Power's recommendations to maximize customer participation. The report will also provide the utilities with a greater level of detail about customer curtailment and the costs of education efforts in relation to curtailment performance.

One provision of the settlement is not entirely clear, and in order to avoid future confusion, we state our interpretation of that provision. Specifically the provision requiring a test event if no events are called before November 2009,

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[280] PG&E Exhibit 201, Chapter 2, p. 58 and February 2008 Guidance Ruling in R.07-01-041, p. 22.

[281] Settlement Agreement Between PG&E and SF Power, March 25, 2009, p. 4 and February 2008 Guidance Ruling in R.07-01-041, p. 24.

[282] Motion of PG&E and SF Power for Approval of Settlement Agreement, March 25, 2009, p. 4.

[283] February 2008 Guidance Ruling in R.07-01-041, p. 22.

does not fully explain the calculation of payments for that test event. Specifically, the proposed settlement states:

> "If no [Capacity Bidding Program] events (or test events) are called during 2009 PG&E will call a SCAP specific test event to calculate the payment due under this section. The maximum payment under this section will be $60,000."[284]

The implication of this term is that the payment would be calculated in the same way that payments would be calculated for an actual event ($16 per kilowatt that PG&E will pay to SF Power for load reductions between 1.4 megawatts and 5 megawatts during actual events), but this is not clearly stated.[285] Given that these parties have struggled with the meaning of the language in previous decisions, we require that the calculation of payment for a pilot-specific test event under this provision, if one is needed, shall be calculated in the same way as payment for a test event. With this clarification, we find the settlement reasonable and adopt it.

22.2. Additional SF Power Issues

In addition to its proposal to continue the Small Commercial Aggregation Pilot and its comments on various demand response programs considered in the discussions of these programs, SF Power also makes several other proposals. SF Power suggestions include advocating adoption of a demand response pilot program focused on municipal water pumping, providing access to the Technical Incentives program to participants in this pump load pilot, and

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[284] Settlement Agreement Between Pacific Gas and Electric Company and San Francisco Community Power, March 25, 2009, p. 5.

[285] $60,000/ $16/kW = 3,750 kW or 3.75 MW. 3.75 MW + 1.4 MW = 5.15 MW

allowing commercial customers to consolidate multiple meters at a single facility into one meter. SF Power also advocates for the replacement of APX as the provider of Web-based services to demand response participants and aggregators; this proposal is not sufficiently described and supported and will not be adopted.

22.2.1. Municipal Water Pumping

SF Power requests approval for a pilot to examine the potential to obtain demand response by automating certain water pumps of municipalities and water districts. SF Power argues that water pumps are well suited to installation of automated demand response technologies, and could be a source of peak load savings.[286] SF Power requests $400,000 to support this pilot.

PG&E argues that a pilot focusing on the application of automated demand response to water pumps, or any single end use, is premature.[287] PG&E also asserts that because water pumps are already subject to time of use rates that discourage use at peak times, "electric pumps typically do not operate during peak hours."[288] Because of this, PG&E states that a pilot of the design proposed by SF Power is unlikely to show a significant amount of demand response.[289]

The water pumping pilot proposed by SF Power is designed to focus on a very narrow subset of customers, and the pilot proposal is not detailed. Given the narrow focus of the proposed pilot and the fact that customers eligible for the

[286] SF Power Opening Brief, p. 27.

[287] PG&E Opening Brief on SF Power, p. 11.

[288] PG&E Opening Brief on SF Power, p. 12.

[289] PG&E Opening Brief on SF Power, p. 12.

pilot are already subject to time of use rates that encourage off-peak use, it is unlikely that this pilot would show significant savings, and we decline to adopt it at this time.

22.2.2. Meter Consolidation

SF Power proposes that, as PG&E installs advanced meters within its service territory, commercial customers that have more than one meter at a single facility should be allowed to consolidate those meters into a single meter that serves the entire facility. SF Power further suggests that customers electing to consolidate meters should be paid an incentive related to the amount saved on the installation of additional AMI meters. SF Power argues that this would save ratepayers from financing the potentially substantial costs of replacing "unnecessary" meters throughout the PG&E service territory, and would save individual customers that currently have multiple meters any costs associated with the operation of those meters, potentially including extra customer charges. SF Power also asserts that having a single meter for all load at a given facility would simplify participation in demand response programs for some customers, leading to increased demand response and lower energy charges for those customers, among other possible positive effects.[290]

PG&E objects to this proposal, asserting that the cost of an advanced meter is fairly low, so the cost savings from meter consolidation would not be high. PG&E also contends that the work required to upgrade wiring and electrical panels to accommodate a larger, single meter for a facility that currently has two or more smaller meters is potentially expensive. For these reasons, PG&E asserts

[290] SF Power Opening Brief, pp. 30-31.

that an incentive of half of the cost of the meter savings would be insufficient to encourage customers to pay for the necessary rewiring to make consolidation possible.[291]

This is an interesting proposal, however, there is little information available at this time on either the costs or the benefits of this program. In addition, no party has offered specific information to show that customers are interested in consolidating their meters, and it is not clear whether doing so would actually encourage demand response. We decline to adopt this proposal at this time. If SF Power or another party makes a similar proposal in the future, it should be supported by additional information on costs, benefits, and levels of customer interest.

23. Evaluation, Measurement and Verification Activities

Evaluation, measurement and verification (EM&V) studies provide information about demand response program attributes, customer acceptance, load impact, and evaluation techniques. The utilities conduct joint evaluations of several statewide demand response activities, such as the Demand Bidding Program, the Base Interruptible Program, Marketing and Outreach, the Demand Response Statewide Awareness Campaign, and for dynamic tariffs available throughout the state, such as Critical Peak Pricing, Real Time Pricing, and Peak Time Rebates. Evaluations of statewide programs are overseen by the Demand Response Measurement and Evaluation Committee (DRMEC). In addition to joint studies of statewide activities, the utilities request funding in this application to evaluate their individual demand response activities and dynamic

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[291] Opening Brief on SF Power proposals, February 4, 2009, pp. 13-14.

pricing tariffs, some of which receive administration or incentives funding in other proceedings.

In addition, the utilities propose to conduct their own evaluation of their individual (non-statewide) programs. PG&E requests a total of $9.5 million for these EM&V studies. SCE requests $6,912,899 for 2009-2011 for demand response-related evaluation, measurement, and verification activities.[292] SDG&E requests $4.1 million for evaluation, measurement, and verification of its Demand Response programs.

23.1. Party Positions on EM&V Funding

TURN suggests that SDG&E's EM&V funding request is inflated compared to that company's previously recorded costs, which indicate that SDG&E spent only 43% of its 2006-2008 evaluation, measurement, and verification budget. TURN proposes reducing SDG&E's evaluation, measurement, and verification budget to $0.616 million.[293] SDG&E responds that TURN misunderstands the nature of SDG&E's cost recovery mechanism, which differs from that of SCE and PG&E. Unlike SCE and PG&E, SDG&E collects its demand response funds through rates after the money has been spent.[294] Because of this, SDG&E will only collect the amount actually spent on evaluation, measurement, and verification, not the full amount approved if it exceeds the amount spent.

TURN recommends reducing SCE's evaluation, measurement, and verification budget to $1,500,000 in total for 2009-2011 based on historical

[292] SCE Opening Brief, p. 27.

[293] TURN Opening Brief, p. 51.

authorization and spending for EM&V by SCE. TURN also specifically argues that no money should be authorized for AMI related evaluations.[295] SCE explains in its amended testimony that it proposes to evaluate time differentiated rates and tariffs that will be introduced as meters are replaced.[296] The utility also proposes to submit a formal evaluation plan to describe the approaches to estimate load impacts of these AMI related tariffs or programs. SCE argues that it also has additional compliance requirements since the 2006-2008 funding was authorized, such as the ex ante and ex post load impact studies. The utility also suggested that if the EM&V budget is reduced to the level proposed by TURN, it would limit the number of programs the utility is able to evaluate and increase the financial burden of statewide evaluation on the other utilities.[297]

23.2. Discussion

EM&V activities, which include program evaluation, load impact evaluation, and demand response research projects, are essential to the development of effective, and cost effective, demand response programs in California. Ratepayer funds are limited and should be spent wisely, and EM&V activities help the Commission determine what activities should continue and how to improve those activities. It is reasonable to approve EM&V funding associated with approved demand response programs, pilots, and related activities. The funding levels proposed by the utilities appear generally to be

[294] SDG&E Reply Brief, pp. 3-4.

[295] TURN Opening Brief, p. 43.

[296] SCE Exhibit 1, p. 225.

[297] SCE Opening Brief, p. 26.

reasonable compared the past EM&V funding to the extent that the underlying programs to be evaluated are approved.

As noted by TURN, the SCE and SDG&E funding requests seem large in comparison to the amounts SDG&E has reported spending on related activities during 2006-2008. TURN fails to acknowledge that the Bridge Funding decision, D.08-12-038, requires the utilities to use unspent 2006-08 EM&V funds to continue EM&V activities related to the 2006-2008 programs, meaning that there may be additional evaluation costs for 2006-2008 that have not yet been recorded. Also, in D.08-04-050, the Commission approved protocols for estimating demand response load impacts and increasing the EM&V requirements on the utilities over the requirements in place earlier in 2006-2008. In addition, SDG&E's cost recovery mechanism provides a safeguard, ensuring that only the amounts actually spent are recovered. To further ensure that EM&V funds are well spent, we note that the utilities are already required to evaluate the statewide programs under the oversight of the DRMEC, and we extend this oversight requirement to all of the utilities' EM&V activities, including those related to utility-specific programs.

The EM&V budgets requested by the utilities appear reasonable, with some changes to reflect other aspects of this decision. Specifically, it is not necessary to provide funding for evaluation of activities that we are denying or discontinuing in this application, so we reduce the PG&E's EM&V budget to remove costs associated with evaluation of the Business Energy Coalition/Automated Business Energy Coalition. Evaluation costs associated with pilots proposed by the utilities appear to be included in the budgets of the specific pilot programs and so are approved or denied along with the pilots themselves, discussed in Section 14, above.

We approve the following EM&V budgets for the three utilities:

	2009-2011 Requested Budget	2009-2011 Authorized Budget
PG&E	$9,562,000	$9,062,000
SDG&E	$4,105,832	$4,105,832
SCE	$7,074,990	$7,074,990

23.3. Authority to Continue the Demand Response Measurement and Evaluation Committee

Evaluation, measurement, and verification activities of the utilities are generally overseen by the Demand Response Measurement and Evaluation Committee (DRMEC), which is composed of members from the California Public Utilities Commission, the California Energy Commission, and each of the three utilities. Previous Commission decisions created the DRMEC and authorized it to oversee the evaluation of statewide demand response activities; this authority was confirmed most recently in D.06-11-049. We authorize the DRMEC to continue its oversight of demand response EM&V activities. Specifically, we require that beginning with the evaluations of 2009 demand response programs, the DRMEC will oversee not only the evaluation of statewide demand response activities, but also the evaluation of activities conducted by the individual utilities.

In addition, we require the DRMEC to conduct an annual public workshop presenting the results of demand response evaluations conducted under the DRMEC's oversight. This annual workshop will be noticed to the most recent service list of this proceeding.

24. Approved Budgets and Authorized Expenses

We approve the following budgets for the utilities' demand response programs:

Table 24-1: SCE

SCE 2009-2011 Demand Response Programs & Forecast Budgets	**Budget Request**				
Category 1 - Emergency Response Programs	**2009 Budget**	**2010 Budget**	**2011 Budget**	**Total Budget Request**	**Total Authorized Budget 2009-2011**
Agriculture & Pumping Interruptible	641,676	453,058	434,730	1,529,464	1,400,000
BIP	2,140,352	1,680,752	1,247,652	5,068,756	4,702,374
OBMC	65,998	65,998	65,998	197,994	197,994
Rotating Outages	136,246	136,246	136,246	408,738	408,738
SLRP	17,665	17,665	17,665	52,995	52,995
Summer Discount Plan	12,878,224	13,948,224	14,108,224	40,934,672	30,334,000
Category 1 Total	***15,880,161***	***16,301,943***	***16,010,515***	***48,192,619***	***37,096,101***
Category 2 - Price Responsive Programs					
Capacity Bidding Program	638,299	174,000	-	812,299	812,299
Critical Peak Pricing (VCD &GCCD)	1,715,153	598,153	328,153	2,641,459	2,641,459
Demand Bidding Program	254,939	5,000	-	259,939	259,939
Energy Options Program	2,317,633	1,947,367	1,438,863	5,703,864	5,703,864
Real Time Pricing	23,473	23,473	23,473	70,419	70,409
Category 2 Total	***4,949,497***	***2,747,983***	***1,790,489***	***9,487,969***	***9,487,970***
Category 3 - DR Aggregator Managed Programs					
Proposed Contracts	9,117,646	16,152,646	21,394,896	66,407,177*	38,773,160***
Category 3 Total	***9,117,646***	***16,152,646***	***21,394,896***	***66,407,177***	38,773,160
Category 4 - DR Enabled Programs					
Automated Demand Response	1,377,627	1,702,627	1,222,627	4,302,881	4,302,881
Agriculture Pump Timer Program	42,006	42,006	42,006	126,018	126,018
Emerging Markets & Technologies	2,971,085	3,196,085	3,077,235	9,244,405	9,244,405
Technical Assistance/Technical Incentives	19,549,175	15,379,175	15,334,175	50,262,525	50,262,525
Category 4 Total	***23,939,893***	***20,319,893***	***19,676,043***	***63,935,829***	***63,935,829***

Category 5 - Pilots & Smart Connect Enabled Programs					
Participating Load Pilot	1,852,867	1,270,467	895,467	4,018,801	3,600,000*
SmartConnect Thermostats for CPP	-	465,710	314,964	780,674	780,674
Smart Thermostat Customer Experience Pilot	416,005	153,745	-	569,750	569,750
Tier Alert	577,555	1,267,657	1,614,637	3,459,849	-
Category 5 Total	***2,846,427***	***3,157,579***	***2,825,068***	***8,829,074***	***4,950,424***
Category 6 - Statewide Marketing Program					
Flex Alert Network	1,649,330	1,649,330	1,649,330	4,947,991	4,947,991
Category 6 Total	1,649,330	1,649,330	1,649,330	***4,947,991***	***4,947,991***
Category 7 - Measurement & Evaluation					
Measurement & Evaluation*	2,449,663	2,337,663	2,287,663	7,074,990	7,074,990
Category 7 Total	2,449,663	***2,337,663***	***2,287,663***	7,074,990	***7,074,990***
Category 8 - System Support Activities					
DR Forecasting*	634,151	234,151	234,151	1,102,453	1,102,453
DR Resource Portal	1,410,000	675,000	450,000	2,535,000	2,535,000
DR System Infrastructure	4,456,989	2,856,989	2,206,989	9,520,967	9,520,967
Category 8 Total	***6,501,140***	***3,766,140***	***2,891,140***	***13,158,420***	***13,158,420***
Category 9 - Marketing Education & Outreach					
Agriculture and Water Outreach	163,023	163,023	163,023	489,069	489,069
Circuit Savers	443,396	510,396	575,396	1,529,188	1,529,188
Federal Power Reserve Partnership	508,423	588,423	588,423	1,685,269	1,685,269
Income Qualified Customer Outreach	40,256	40,256	40,256	120,768	120,768
Integrated DSM Marketing	984,359	984,359	984,359	2,953,077	2,953,077
DR Energy Leaders Partnership	868,031	868,031	868,031	2,604,093	2,604,093
Category 9 Total	***3,007,488***	***3,154,488***	***3,219,488***	*9,381,464*	*9,381,464*
Category 10 - Integrated Programs **					
Commercial New Construction Integrated Delivery	285,799	285,799	285,799	857,397	**n/a**
Residential New Construction Integrated Delivery	376,655	26,655	26,655	429,965	**n/a**
EARTH/Smart Student Program	51,369	51,369	51,369	154,107	**n/a**
Innovative Designs for Energy Efficiency Activities	186,767	186,767	186,767	560,301	**n/a**
Institutional Partnership Program	179,039	79,039	79,039	337,117	**n/a**
IDSM Pilot for Food Processing					**n/a**

	133,549	83,549	83,549	300,647	
Technology Resource Incubator Outreach	106,667	106,667	106,667	320,001	n/a
Category 10 Total	*1,319,845*	*819,845*	*819,845*	*2,959,535*	*n/a*
Total Requested in 2009-2011 Applications	71,661,090	70,407,520	72,564,477	234,375,078	
Total Requested minus adjusted contracts and IDSM programs				203,781,526	
Total Authorized 2009-2011					188,806,349

* D.08-12-038 authorized bridge funding for SCE's Participating Load Pilot at approximately $3.6 million. This funding covers the 2009- 2011 period and is intended to be augmented with funds left over from SCE's 2006-2008 DR program budget. SCE's spending to date on their Participating Load Pilot in 2009 should be subtracted from the $3.6 million designated in this decision.

** These programs will be reviewed and decided on through the EE 2009-2011 Program Portfolio Application, 08-07-021 as per the Assigned Commissioner and Administrative Law Judge Ruling on March 26, 2009.

*** Includes some funding for aggregator contracts in 2012.

Table 24-2: PG&E

	Budget Request				Total authorized for 2009-2011
	2009	**2010**	**2011**	**Total**	
Category 1 - Emergency Programs					
BIP	$365,000	$472,000	$406,000	$1,242,000	$800,000
OBMC/SLRP	$40,000	$42,000	$56,000	$138,000	$138,000
Smart AC	-	-	-	-	-
Category 1 Total	$405,000	$514,000	$462,000	$1,380,000	$938,000
Category 2 - Price Response Programs					
DBP	$1,072,000	-	-	$1,072,000	$3,216,000
CPP	$1,222,000	$1,165,000	$1,126,000	$3,513,000	$3,514,000
CBP	$1,537,000	$2,589,000	$2,548,000	$6,674,000	$3,615,076
Peak Choice	$4,801,000	$5,703,000	$6,450,000	$16,954,000	$9,000,000
DWR	-	-	-	-	
Category 2 Total	$8,632,000	$9,457,000	$10,124,000	$28,213,000	$19,345,076
Category 3 - DR Service Provider (Aggregators) Managed Programs					
Aggregator Managed Portfolio	$925,000	$1,008,000	$1,178,000	$3,111,000	$2,772,000
BEC***	$1,741,000	$1,694,000	$1,799,000	$5,233,000	$4,623,996
Auto BEC (ABEC)	$3,381,000	$3,328,000	$3,441,000	$10,149,000	$0
Category 3 Total	$6,047,000	$6,030,000	$6,418,000	$18,493,000	$7,395,996
Category 4 - DR Enabling Programs					
Integrated Energy Audits	$975,000	$994,000	$973,000	$2,942,000	$2,942,000

TI	$2,944,000	$3,350,000	$4,016,000	$10,310,000	$10,310,000
Auto DR	$4,888,000	$5,254,000	$5,975,000	$16,117,000	$16,117,000
PLS	$40,000	$42,000	$56,000	$138,000	$138,000
DR Emerging Technology	$790,000	$810,000	$820,000	$2,421,000	$2,421,000
Category 4 Total	$9,637,000	$10,450,000	$11,840,000	$31,928,000	$31,928,000
Category 5 – Pilots					
PHEV/EV Pilot				$1,010,000	$1,010,000
C&I Intermittent Resources Pilot				$1,764,000	$1,764,000
Small Customer Load Aggregation Pilot	$853,000	$861,000	$881,000	$2,595,000	$0
Smart AC Ancillary Service Pilot and C&I Ancillary Service Pilot*	$1,198,000	$1,198,000	$1,198,000	$3,594,000	$3,494,000
SF Power Small Load Aggregation Pilot**	$109,000	-	-	$109,000	$109,000
Category 5 Total	$2,160,000	$2,059,000	$2,079,000	$8,062,000	$6,377,000
Category 6 - Flex Your Power Now					
Statewide DR Awareness Campaign	$3,201,000	$2,133,000	$1,071,000	$6,405,000	$6,405,000
Category 7 - Evaluation, Measurement, and Verification					
Evaluation, Measurement & Verification	$3,557,000	$3,105,000	$2,900,000	$9,562,000	$9,062,000
Category 8 - System Support Activities					
InterAct/DR Forecasting Tool	$3,437,000	$3,469,000	$3,506,000	$10,413,000	$10,413,000
DR On-Line Enrollment	$2,394,000	$2,106,000	$1,989,000	$6,489,000	$6,489,000
Legacy DR Conversion	$1,581,000	$1,600,000	$1,647,000	$4,828,000	$0
Marketing Decision Support System (MDSS) Upgrade	$1,242,000	$1,180,000	$678,000	$3,100,000	$0
Capital - MDSS Upgrade	$1,608,000	$1,061,000	$185,000	$2,854,000	$0
Capital – Interval Meters	$800,000	$500,000	$500,000	$1,800,000	$0
Category 8 Total	$11,062,000	$9,916,000	$8,505,000	$29,484,000	$16,902,000
Category 9 - DR Core Marketing and Outreach					
DR Core Marketing and Outreach	$3,210,000	$3,214,000	$2,916,000	$9,339,000	$9,339,000
Education and Training	$502,000	$428,000	$439,000	$1,368,000	$1,368,000
Category 9 Total	$3,712,000	$3,642,000	$3,355,000	$10,707,000	$10,707,000
Category 10 Integrated Programs					
PEAK	$542,000	$544,000	$552,000	$1,639,000	n/a
Integrated Marketing and Training	$333,000	$333,000	$333,000	$1,000,000	n/a
Integrated Education and Training	$67,000	$67,000	$67,000	$200,000	n/a
Integrated Sales Training	$83,000	$83,000	$83,000	$250,000	n/a
IDSM Clearinghouse	$167,000	$167,000	$167,000	$500,000	n/a
Category 10 Total	$1,192,000	$1,194,000	$1,202,000	$3,589,000	n/a
Overall TOTAL	**$49,605,000**	**$48,500,000**	**$47,956,000**	**$147,823,000**	**$109,060,072**

Reference

PG&E 2009-2011 DR Programs and Budgets Amended Prepared Testimony, Sept. 19, 2008, pg 1-13

* PG&E 2009-2011 DR Programs and Budgets Appendices, Sept. 19, 2008, Appendix 2C; approved in Bridge Funding Decision

** Settlement which includes the Bridge Funding

** Budget for 2009 only, approved in Bridge Funding Decision

Table 24-3: SDG&E

	Requested Budget				**Authorized Budget**
	2009	2010	2011	Total	Total
Demand Response Program					
Category 1: Emergency Programs					
Base Interruptible Program	559,804	554,642	542,621	1,657,067	1,475,423
Emergency Critical Peak Pricing	126,985	106,867	94,689	328,541	328,541
Summer Saver Program	0	0	0	0	0
Optional Binding Mandatory Curtailment	0	0	0	0	0
Scheduled Load Reduction Program	0	0	0	0	0
Category 1 Total	**686,111**	**661,509**	**637,310**	**1,985,608**	**1,803,964**
Category 2: Price-Responsive Programs					
Default Critical Peak Pricing	0	0	0	0	0
Peak Time Rebate Program	0	0	0	0	0
Capacity Bidding Program	1,998,657	2,232,147	2,601,179	6,831,983	6,426,173
Peak Day Credit Program	328,000	0	0	328,000	328,000
Demand Bidding Program	492,000	0	0	492,000	492,000
Category 2 Total	**2,818,657**	**2,232,147**	**2,601,179**	**7,651,983**	**7,246,173**
Category 3: Aggregator Programs	n/a	n/a	n/a	n/a	n/a
Category 3 Total	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**
Category 4: DR Enabling Programs					
Technical Assistance	3,322,805	3,337,097	3,351,424	10,011,326	10,011,326
Technology Incentives	4,353,880	4,274,764	4,034,197	12,662,841	12,662,841
Demand Response--Emerging Technologies	717,743	708,148	716,604	2,142,495	2,142,495
Permanent Load Shifting	-	-	-	308,371	308,371
Category 4 Total				**24,816,662**	**24,816,662**
Category 5: Pilot Programs					
Participating Load Pilot*	-	-	-	3,756,000	3,756,000
Residential Automated Controls Technology	551,217	544,415	594,039	1,689,671	1,689,671
Category 5 Total				**5,445,671**	**5,445,671**
Category 6: Statewide Marketing Program					

Flex Alert Network	626,943	417,962	208,981	1,253,886	1,253,886
Category 6 Total	**626,943**	**417,962**	**208,981**	**1,253,886**	**1,253,886**
Category 7: Evaluation, Measurement& Verification					
Evaluation, Measurement& Verification	1,167,100	1,585,166	1,352,559	4,104,825	4,105,832
Category 7 Total	**1,167,100**	**1,585,166**	**1,352,559**	**4,104,825**	**4,105,832**
Category 8: System Support Activities					
Codes & Standards	200,000	200,000	200,000	600,000	0
Category 8 Total	**200,000**	**200,000**	**200,000**	**600,000**	**0**
Category 9: Marketing, Education and Outreach					
Customer Education, Awareness & Outreach	1,800,754	2,009,733	2,218,722	6,943,854	6,943,854
Category 9 Total	**1,800,754**	**2,009,733**	**2,218,722**	**6,943,854**	**6,943,854**
Category 10: IDSM	n/a	n/a	n/a	n/a	n/a
TOTAL	17,709,134	13,961,208	13,696,293	51,982,489	51,643,042

*Approved in Bridge Funding Decision.

The budgets approved in this decision and reflected in these tables include the amounts previously approved for 2009 activities in the Bridge Funding decision, D.08-12-038. The Bridge Funding amounts for each program continuing through 2010 and 2011 are included in the total budget for that program. For programs to be discontinued after the adoption of this decision, the amounts previously approved for 2009 are enumerated in separate line items and included in the total authorized funding amounts for 2009-2011.

The approved budget for SCE is significantly larger than the approved budget for PG&E, despite the fact that these utilities are of relatively comparable size. There are two main reasons for this. First, SCE requests and receives funding for two aggregator contracts with a total funding of approximately $38,000,000 through 2012. Second, SCE requests (and receives) significantly higher budgets for Technical Assistance and Technology Incentives than either of the other utilities. These two budget categories account for most of the difference between the approved budgets of PG&E and SCE.

25. Program and Budget Changes During 2010 and 2011

The February 2008 Guidance Ruling directs that future program development or modifications to existing demand response programs should be made through new applications to the Commission or petitions to modify the decision(s) in which a program was adopted.[298] Several parties, including the applicants and the CAISO, suggest that it would be faster and more efficient for some program modifications or budget increase requests to be evaluated through the advice letter process.

25.1. Utility Proposals on Program and Budget Changes During 2010 and 2011

In its application, PG&E asserts that its demand response programs are likely to require revision during the 2009-2011 period to account for changes in the CAISO markets, among other possible developments.[299] According to PG&E, changes to program tariffs and contracts to align them with CAISO user guides and tariffs should not go through the formal application process due to the length of time that process can take. PG&E recommends that the Commission allow the utilities to use an advice letter process to request program modifications. PG&E does not limit its request to changes needed to streamline programs and increase their consistency with the new CAISO market processes as they evolve, recommending that the Advice Letter process be available to change more than "unexpected features" of the new CAISO market. Specifically,

[298] Guidance Ruling February 2008, p. 10.

[299] PG&E Exhibit 201, Chapter 3, pp. 16-17.

PG&E requests that the Commission permit the utilities to request changes to demand response programs and aggregator contracts through Advice Letter filings.[300] SCE generally supports this PG&E request.

PG&E asserts that the application process is time-consuming and if the changes being requested are within the overall funding approved for each specific category of programs and would not require an overall budget increase, the advice letter process should be used.[301] PG&E also argues that the utilities need to retain the ability to revise programs by advice letter to reflect the operational changes required to coordinate with the new CAISO market, and later with the new CAISO market Release 1 or MAP (Market and Performance), without procedural delays.[302] PG&E emphasizes its position that the advice letter review process used for past program modifications was not put in place to circumvent review; it was intended to expedite review to keep the programs current.

SDG&E offers extensive supporting arguments in support of its proposal to establish an annual process to modify demand response programs.[303] SDG&E believes that the demand response portfolio, and customer acceptance and participation these programs, can be enhanced by the establishment of an annual advice letter process to request and approve program modifications.[304] SDG&E

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300 PG&E Exhibit 201, Chapter 3, pp. 16-17.

301 Opening Brief of Pacific Gas and Electric Company (U 39-E), January 28, 2009, at p. 15.

302 PG&E Opening Brief.

303 SDG&E Exhibit 102A, pp. 66-72.

304 SDG&E Exhibit 102A, p. 68.

proposes that the Commission authorize utilities to file an annual Advice Letter, no later than October 15 of each year during the 2009-2011 program cycle. The primary purpose of these annual Advice Letters would be to propose specific program changes, based on the utility's ongoing experience and customer feedback regarding demand response program operations, designed to enhance the portfolio of authorized demand response programs for succeeding years within the 2009-2011 program cycle.[305] SDG&E recommends that the Commission issue a resolution or otherwise address the annual Advice Letter filings by January 1 of each year during the 2009-2011 program cycle. According to SDG&E, approval by January 1 of each year would enable SDG&E to maintain the continuity of its demand response program portfolio, incorporate any proposed and approved program changes, and communicate with its potential program participants with a lead time sufficient to allow those customers to address their internal issues and processes in advance of the summer demand response season.[306]

25.2. Party Positions on Methods for Program Modification

CAISO supports the utilities' request to use the advice letter process to expedite changes to utility programs, stating that "the Commission should support and allow the utilities to make adjustments to new demand response programs, or apply for new programs, via Advice letters."[307] The CAISO contends that the utilities will need flexibility to adjust their programs as the

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[305] SDG&E Exhibit 102A, p. 70.

[306] SDG&E Exhibit 102A, p. 72.

[307] CAISO Opening Brief.

CAISO adds additional functionality and enhancements for demand response resources as the new CAISO market develops.

25.3. Discussion

As described in General Order (GO) 96-B, the advice letter process provides an expedited process for review of utility requests that are expected to be neither controversial nor likely to raise important policy questions. GO 96-B explains further that the primary use of the advice letter process is to review a utility's request to change its tariffs in a manner previously authorized by statute or Commission order, to conform the tariffs to the requirements of a statute or Commission order, or to get Commission authorization to deviate from a utility tariff.[308]

This current applications proceeding provides the opportunity for utilities to present their demand response programs for the next three year cycle. The application process ensures appropriate review of the utilities' many demand response proposals, and provides an opportunity for interested parties and members of the public to provide input and make alternative proposals. The application process also allows the Commission to build an adequate record on which to determine what programs and related policies should be adopted for the next several years.

As the utilities propose changes to existing programs during the next program cycle it is important to preserve the ability to examine and receive party input on changes that would affect the total budget adopted in this decision, or would create new programs or program components (such as the creation or

[308] GO 96-B at Part 5.

elimination of a new option under PG&E's PeakChoice or SCE's Energy Options Program) that have not been publicly evaluated. The advice letter process, which is intended for non-controversial updates or changes to existing programs, is not appropriate for the review of new programs or an increase in the total budget for a program area adopted in a decision. Such changes should be requested through a petition for modification of the decision adopting the program, for modifications to existing programs, or through a new application, for a new program. Changes to policies specifically adopted in this or another decision, such as the calculation of a settlement baseline for an existing program or rules for concurrent participation in multiple programs, should also be made through an application or petition for modification. Modifications of existing aggregator contracts should also be requested through a new application or petition for modification.

Rules for shifting of funds approved in this decision among already-approved programs are discussed in Section 26, below. In order to facilitate changes to streamline existing programs and improve their ability to function within the new CAISO market, we authorize the utilities to request other changes, including non-controversial changes to program tariffs and implementation procedures, via a Type 2 advice letter. If uncertain whether a particular change is appropriate for review through the advice letter process, utilities are encouraged to consult with Energy Division staff (and interested parties, if appropriate) before submitting an advice letter. The utilities' applications for the 2012-2014 period shall be filed by January 30, 2011.

26. Fund Shifting Rules

In D.06-03-024, the Commission approved fund shifting rules to be used throughout the 2006-2008 period. These rules provide the following:

- Utilities may shift up to 50% of funds of a program's funds to another program within the same budget category without filing an advice letter, as long as no program is eliminated without prior authorization from the Commission.

- Motions or advice letters are necessary for fund shifting that exceeds the 50% threshold, or to propose new programs to be implemented within the 2006-2008 funding level.

- Unused funds from one year may be carried over to the subsequent year, and the utilities may file requests for incremental funding for new or existing programs by advice letter or application.

- For SCE's Technical Assistance and Technology Incentives program only, fund shifting is limited to 25% of program funds. [309]

26.1. Utility Proposals for Fund-Shifting Rules

SCE proposes to continue the fund-shifting flexibility authorized in D.06-03-024, in an effort to ensure that funds are deployed efficiently and focused on programs it views to be successful.[310] According to SCE, no party has made any showing that the existing fund shifting rules should not continue into the 2009-2011 program cycle.[311]

PG&E urges the Commission to provide the utilities with broader authority to shift funds among programs without advance Commission approval. SDG&E provides the most detailed proposals, contending that in

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[309] D.06-03-024, March 15, 2006. Decision Adopting Settlement, pp. 13-15.

[310] PG&E Exhibit 201, p. 13.

[311] SCE Opening Brief, p. 51.

order to maintain fund-shifting flexibility comparable to that authorized during the 2006-2008 period, the Commission should authorize the following rules for 2009-2011:[312]

- Retain for the 2009-2011 program cycle the existing flexibility to reallocate up to 50% of authorized budget funds between programs within each of four budget categories. SDG&E proposes that these categories should be (1) specified programs, (2) statewide informational, educational, and developmental programs, (3) Technical Assistance/Technical Incentives/ automated demand response, and (4) other programs. As is currently the case, no program authorized and funded by the Commission would be terminated without prior Commission authorization.

- Up to 25% of authorized budget funding for a category may be shifted to programs in a different category.

  a. Proposals to shift program budget funding within authorized budgets but ***exceeding*** these 25% or 50% guidelines may be requested by Advice Letter.

  b. Retain the existing ability to carry unspent funds into subsequent years within the 2009-2011 program cycle.

SDG&E also proposes that it retain the right to file any proposals or requests for incremental funding for new or existing programs by Advice Letter; as discussed in Section 25, above, we do not approve this request, and require utilities to submit an application to request funding beyond the total budget approved in this decision.

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[312] SDG&E, Exhibit 102, pp. 69-70.

26.2. Discussion

There were no significant party concerns about the utilities' fund shifting proposals. In their applications, the utilities assert that the flexibility to shift funds between program categories is essential to operating their demand response programs. The costs to operate effective demand response programs do vary over time and from year to year, along with weather conditions within the state and changes in enrollment. It is apparent from the utilities' applications, and especially from their proposals to transition demand response programs to function within the new CAISO market, that some program changes and budget flexibility will be needed during the 2009-2011 period to enable the utilities to adjust their programs for changes in electricity markets and other conditions.

The purpose of this application is to build a record on which to determine reasonable design characteristics and funding levels for demand response in 2009-2001. This proceeding has considered the factors that may lead to the need for flexibility in funding. Many parties have provided input during this proceeding, and these factors have been taken into consideration in determining the total funding level for the utilities' programs. While it is clear that good estimates are not yet available for some of the developments expected over the next two years, the budgets authorized in this decision take those developments into account, and Section 25, above, outlines a process for utilities to request additional funding through an application or petition for modification of a previous decision, if necessary.

It is reasonable to provide the utilities with some flexibility to shift funds among demand response programs, in order to provide the utilities with the ability to respond effectively to unforeseen developments that may occur, or to respond to changing conditions. As in the discussion of the appropriate process for requesting new demand response programs or additional funding beyond the total allocated in this decision, it is appropriate that major changes to the relative funding of specific programs be subject to thorough review and party comment. Providing utilities with broad authority to shift funds among programs without prior notification or approval of this Commission undermines the regulatory process through which this decision was developed. The program budgets adopted here become meaningless if large portions can be shifted to different programs or budget categories. We adopt the following rules for fund shifting in 2009-2011:

- The utilities may shift up to 50% of a program's funds to another program within the same budget category. Utilities will document the amount of and reason for each shift in their monthly demand response reports.

- The utilities must file an advice letter to eliminate a program. No program can be eliminated through multiple fund shifting events or for any other reason without prior authorization from the Commission.

- The utilities must file a Tier 2 advice letter before shifting more than 50% of a program's funds to a different program within the same budget category. If shift of more then 50% of a program's funds is necessary as part of the implementation of a new program, the fund shift should be included in application for approval for the new program.

- The following lists contain the ten program categories for fund shifting purposes, along with various programs authorized within each category. Utilities shall not shift funds between these ten categories:

SCE 2009-2011 Demand Response Program Categories	**SDG&E 2009-2011 Demand Response Program Categories**	**PG&E 2009-2011 Demand Response Program Categories**

SCE 2009-2011 Demand Response Program Categories	**SDG&E 2009-2011 Demand Response Program Categories**	**PG&E 2009-2011 Demand Response Program Categories**
Category 1 - Emergency Programs		
Base Interruptible Program	Base Interruptible Program	Base Interruptible Program
Summer Discount Plan	Summer Saver Program	Smart AC
Optional Binding Mandatory Curtailment Program	Optional Binding Mandatory Curtailment Program	Optional Binding Mandatory Curtailment Program
Scheduled Load Reduction Program	Scheduled Load Reduction Program	Scheduled Load Reduction Program
Rotating Outages		DWR contract
Agriculture & Pumping Interruptible		
Category 2 - Price Responsive Programs		
Capacity Bidding Program	Capacity Bidding Program	Capacity Bidding Program
Critical Peak Pricing	Default Critical Peak Pricing	Critical Peak Pricing
Demand Bidding Program	Emergency Critical Peak Pricing	Demand Bidding Program
Energy Options Program	Peak Time Rebate Program	Peak Choice
Category 3 - DR Aggregator Managed Programs		
Proposed Contracts	**(none)**	AMP
Category 4 - DR Enabled Programs		
Automated Demand Response	Technical Assistance	Integrated Energy Audits
Agriculture Pump Timer Program	Technology Incentives	Technology Incentives
Emerging Markets & Technologies	Demand Response--Emerging Technologies	Auto DR
Technical Assistance	Permanent Load Shifting (Gas A/C -- Cypress and Refrigerated Zone Modules -- EPS)	Permanent Load Shifting
Technical Incentives		DR Emergency Technology
Permanent Load Shifting		
Category 5 - Pilots & Smart Connect Enabled Programs		
Participating Load Pilot	Residential Automated Controls Technology	Renewable Pilot
SmartConnect Thermostats for CPP		Small Customer Load Aggregation Pilot
Smart Thermostat Customer Experience Pilot		Ancillary Service Pilots
Category 6 - Statewide Marketing Program		
Flex Alert Network	Flex Alert Network	Flex Alert Network (Statewide DR Awareness Campaign)
Category 7 - Evaluation & Measurement		
Evaluation & Measurement	Evaluation & Measurement	Evaluation & Measurement

SCE 2009-2011 Demand Response Program Categories	**SDG&E 2009-2011 Demand Response Program Categories**	**PG&E 2009-2011 Demand Response Program Categories**
Category 8 - System Support Activities		
DR Forecasting		InterAct/DR Forecasting Tool
DR Resource Portal		DR On-Line Enrollment
DR System Infrastructure		Legacy DR Conversion
		Marketing Decision Support System (MDSS) Upgrade
		Capital - MDSS Upgrade
		Capital – Interval Meters
Category 9 - Marketing Education & Outreach		
Agriculture and Water Outreach	Customer Education, Awareness & Outreach	DR Core Marketing and Outreach
Circuit Savers		Education and Training
Federal Power Reserve Partnership		
Income Qualified Customer Outreach		
DR Energy Leadership Partnership		
Integrated DSM Marketing		
Category 10 - Integrated Programs		
Commercial New Construction Integrated Delivery		PEAK
Earth/Smart Student Program		Integrated Marketing and Training
Innovative Designs for EE Activities		Integrated Education and Training
Institutional Partnership Program		Integrated Sales Training
IDSM Pilot for Food Processing		IDSM Clearinghouse
Residential New Construction Integrated Delivery		
Technology Resource Incubator Outreach		

27. Cost Recovery Mechanisms

The majority of the utilities' requests for cost recovery of demand response program funding are unopposed by parties. These requests largely continue cost recovery approaches adopted during previous demand response budget cycles. This section discusses the utility cost recovery requests, other party positions when appropriate, and the revenue requirements and funding mechanisms adopted for 2009-2011.

27.1. SCE

SCE's total requested funding level of $291.4 million would represent an increase of approximately $93.8 million over the budget for demand response activities for the 2006-2008. SCE is proposing to apply $56.6 million in revenue requirement over four years to recover its projected $291.4 million in demand response program costs. SCE proposes to divide its annual $56.6 million revenue requirement in the following manner:[313]

- $0.890 million would be allocated to the Critical Peak Pricing program and associated with 2009 generation revenue requirement and included in distribution rate levels beginning in 2009.[314]

- $55.7 million would be allocated to SCE's distribution revenue requirement and included in distribution rate levels beginning in 2009.[315]

SCE does not request changes to the currently authorized ratemaking treatment for its demand response programs. Specifically, SCE recovers authorized demand response funding on an annualized basis through the Base Revenue Requirement Balancing Account (BRRBA). Year-end overcollections recorded in the BRRBA are refunded to customers and undercollections are recovered from customers in the subsequent year. SCE proposes to include the

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313 SCE Exhibit 201, p. 233.

314 SCE Exhibit 201, p. 234.

315 SCE Exhibit 201.

2009 demand response funding level authorized in this proceeding in rate levels as part of its next Energy Resource Recovery Account (ERRA) Forecast proceeding.

SCE records the difference between the authorized demand response funding and the actually incurred demand response program expenses in the Demand Response Program Balancing Account (DRPBA), which includes distribution and generation sub-accounts. Consistent with past practice, SCE proposes including the three year operation (i.e., 2009 through 2011) of the DRPBA in its April 2012 ERRA Reasonableness application for Commission approval.

SCE's proposed demand response budget would also include $16.8 million in Demand Response Purchase Agreements, which would be allocated to its generation revenue requirement and included in distribution rate levels beginning in 2009.[316]

SCE proposes no change to its currently authorized ratemaking for its demand response purchase agreements. The current ratemaking approach includes recovery of the actual capacity payments associated with purchase agreements (aggregator contracts) and recovery of the annualized demand response purchase agreement administration funding. SCE records the difference between the authorized and actual administration levels in the Purchase Agreement Administrative Cost Balancing Account (PAACBA). SCE reports on the four-year operation of the PAACBA in its 2013 ERRA

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[316] SCE Exhibit 201.

Reasonableness application for Commission approval. No parties objected to the SCE request to retain its existing cost recovery mechanisms.

Consistent with the determinations made in this decision, we approve a total revenue requirement of $184,041,287, of which approximately $38.8 million is for its purchase agreements, to be collected consistent with SCE's existing cost recovery mechanisms, described in this section.

27.2. SDG&E

SDG&E requests approval of $19.591 million, $20.068 million and $20.956 million in budgeted funds for 2009, 2010 and 2011, respectively, a total of $60.615 million, to fund its Demand Response programs. SDG&E's funding request updates an original request for $48.535 million to include $12.080 million from previously-authorized 2006-2008 Demand Response program budgets to fund its Commission-required Participating Load Pilot program.[317]

SDG&E's regulatory accounting and cost recovery treatment is outlined in D.03-03-036 and D.05-06-017. In its application, SDG&E states that it currently records all program costs associated with its existing Demand Response programs in its Advanced Metering and Demand Response Memorandum Account (AMDRMA). SDG&E records the energy component of the customer incentive payments to its ERRA.

SDG&E is requesting that authorized demand response program costs related to Operation and Maintenance (O&M) expenses, capital related costs (i.e., depreciation, return and taxes), customer capacity incentive payments,

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[317] Amended Application of San Diego Gas and Electric Company (U 902-M) For Approval of Demand Response Programs and Budget For Years 2009 Through 2011, Application 08-06-002, September 19, 2008, p. 8.

participating load pilot costs and all other costs, not recovered through SDG&E's 2008 General Rate Case (GRC), be recorded in AMDRMA.

SDG&E is proposing no change in the disposition of AMDRMA balances; namely, that the balances are transferred to the Rewards and Penalties Balancing Account (RPBA) on an annual basis for amortization in SDG&E's electric distribution rates over 12 months, effective January 1 of each year, consistent with its adopted tariffs. No parties objected to the SDG&E request to retain its existing cost recovery mechanisms.

Consistent with the determinations made in this decision, we approve a revenue requirement of $51,432,413 for SDG&E's 2009-2011 programs, to be collected consistent with SDG&E's existing cost recovery mechanisms, described in this section.

27.3. PG&E

PG&E requests an annual revenue requirement of $148.44 million for its 2009-2011 demand response activities, to be collected from all distribution service customers.[318] In D.06-03-024, the Commission established the Demand Response Revenue Balancing Account (DRRBA) and the Demand Response Expense Balancing Account (DREBA) to track and recover costs of most of PG&E's demand response activities. In addition to these balancing accounts, PG&E is authorized to recover funding for certain specific demand activities through other mechanisms, including the following:

- Costs associated with the Base Interruptible Program (E-Base Interruptible Program) are recovered through PG&E's Distribution Revenue Adjustment Mechanism (DRAM).

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[318] PG&E Exhibit 201, Chapter 8, p. 1.

- Costs associated with the California Department of Water Resources (CDWR) and the Aggregator Managed Portfolio (AMP) incentives are recovered through the EERA.

- Costs associated with Air Conditioning Program expenses are recovered through the Air Conditioning Expense Balancing Account (ACEBA) and DRRBA.

- PG&E will record its MRTU-related information system costs in the MRTU Memorandum Account (MRTUMA) approved by the Commission in Resolution E-4093.

PG&E's DRRBA is a two-way balancing account with a separate rate sub-component that records the actual revenues from customer sales and tracks these revenues against PG&E's authorized revenue requirement. DRRBA is adjusted on an annual basis through the Annual Electric True-Up advice letter filing.

DREBA is a one-way balancing account that tracks actual demand response portfolio expenses against the authorized revenue requirement. Year-end overcollections recorded in the DREBA are refunded to customers, and under-collections are absorbed by PG&E shareholders.

PG&E requests Commission approval to revise its current DREBA mechanism to create a two-way balancing account for event-based demand response program incentive costs. This revision would affect the cost recovery for the Capacity Bidding program, the Demand Bidding Program, and the Peak Choice program.[319] According to PG&E, without a two-way balancing account mechanism, it is possible that the utility might have insufficient funds for certain

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[319] PG&E Exhibit 201, Chapter 8, p. 4.

incentive-based demand response programs if actual events exceed forecasted events. PG&E asserts that such a situation could shut down the affected programs before the end of the current program cycle, or could lead to the dispatch of more costly peak generation resources in the absence of the ability to call on demand response.[320] PG&E explains that its forecast for incentives is not based on extreme conditions such as those that occurred during the 2006 heat storms, and that a two-way balancing would ensure that it is prepared for such dramatic events that may increase demand response program enrollment such as the 2006 heat storms.

27.3.1. Party Comments on PG&E Proposal

TURN recommends that the Commission reject PG&E's request for two-way balancing account treatment. According to TURN, PG&E's request could lead the utility to invest in programs that may not be cost effective.[321] TURN asserts that even during 2006, PG&E spent only a fraction of its authorized incentive budget. This low level of actual incentive deployment occurred during the very conditions that PG&E uses to justify its request for two-way balancing account treatment.

27.3.2. Discussion

PG&E's request for two-way balancing account treatment for the DREBA departs from the cost recovery rules in place for that utility in 2006-2008. The purpose of this proceeding is to estimate the likely level of future activity based on many factors, including past activity, program changes, and forecast growth.

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320 Ibid.

321 Opening Brief of The Utility Reform Network on the Demand Response for 2009-2011: The $360 Million Utility Slush Fund, January 28, 2009 at p. 88.

PG&E, like the other utilities, has provided budget estimates that have been reviewed thoroughly in this proceeding. Based on past program performance, it is extremely unlikely that the incentive budgets authorized in this decision will exceed the approved amounts. However, two-way balancing account treatment for program incentives would allow recovery of additional incentive costs in the unlikely event that such a situation did occur, without requiring additional ratepayer funding unless extreme conditions cause the incentive budget to be exceeded.

The PG&E request to change the DREBA from a one-way to a two-way balancing account for program incentives only is adopted; administrative expenses will continue to be subject to one-way balancing account treatment, and are capped at 50% of the program costs for each approved progam, as provided in this decision. Consistent with the determinations made in this decision, we approve a revenue requirement of $108,980,996 for PG&E's 2009-2011 programs, to be collected consistent with PG&E's cost recovery mechanisms, described in this section.

28. Modification of Reporting Requirements

The scoping memo in this proceeding required SCE, SDG&E, and PG&E to file their previously defined monthly reports on interruptible load and demand response in this consolidated proceeding. These reports contain a variety of information relevant to the understanding and evaluation of the utilities' demand response activities, and are valuable to the Commission and parties because they allow tracking of changes in program participation. For this reason, we require the utilities to continue preparing these monthly reports.

In order to ensure that the information provided in these reports remains useful, however, we require the utilities to work with Energy Division staff to revise the format and content of the existing report. Starting with the year-end report for 2009, and continuing at least through the end of the current budget period, all three utilities will use a consistent monthly report format approved by Energy Division staff. The new reporting format will include the information currently required in these reports, along with some additional information, including (but not necessarily limited to) the following:

- The total number of customers eligible for each program, by customer class. This will provide some context for understanding programs' overall potential.

- For programs that allow customers to choose among different notification times, all participation, load impact, and other data will be reported separately for each combination of trigger options and notification times.

After the adoption of this decision, however, it will no longer be necessary for the utilities to file their monthly reports in what will be a closed docket. Instead, we require the utilities to serve their monthly reports on the director of the Commission's Energy Division, and to provide copies to the most recent service list in this proceeding. In addition, the utilities shall post their monthly reports on a publicly available web site.

29. Transition Period

In D.08-12-039, we approved monthly budgets for existing demand response activities, and made provision for those activities to continue through the end of 2009, if necessary. That decision provided that bridge funding would end no later than three months after the effective date of a final decision in this docket, or on December 31, 2009, whichever comes first.

Many demand response programs are seasonal, with participation either limited to or concentrated in the summer months. This decision is being approved in midsummer of 2009, meaning that new programs or significant program changes cannot be implemented before midsummer 2009. Based on the three-month transition period allowed in the Bridge Funding decision, it is very possible that some programs will not be implemented or modified based on this decision until fall 2009, when some demand response activities may no longer be operating, and others may technically be operational but expect few if any events before the end of the year. Also, customers participate in demand response activities based on an understanding of the specific program's requirements or characteristics, and may wish to discontinue their participation or change to a different activity if the requirements or characteristics change.

In order to minimize administrative difficulties and avoid customer confusion, we authorize the utilities to implement the modifications to policies and program rules affecting existing programs adopted in this decision not later than January 2010, unless otherwise required in this decision. New programs and pilots shall be implemented in 2010, unless otherwise noted in this decision. SCE, SDG&E, and PG&E shall each file one or more Tier 1 compliance advice letters within 90 days of the date of this decision updating their tariffs to be consistent with the requirements of this decision and noting the date on which those changes will take effect.

30. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by BluePoint, CAISO, the Califormia Energy Storage Association, CDRC, CLECA, CPower, DRA, ECS, Ice, PG&E, SCE, SDG&E, Transphase, and TURN, on July 20, 2009, and reply comments were filed on

July 27, 2009, by CDRC, DRA, PG&E, SCE, SDG&E, and TURN. Additions and changes have been made throughout the final decision as appropriate in response to the comments received.

31. Categorization and Assignment of Proceeding

This proceeding is categorized as ratesetting. Rachelle B. Chong is the assigned Commissioner and Jessica T. Hecht is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. The cost effectiveness estimates included in the applications are sufficient to support our review in this proceeding.

2. Emergency-triggered demand response activities are programs that are not triggered by the IOUs in response to wholesale energy market prices, but are instead triggered in response to an actual or imminent declaration by CAISO of a system emergency, or during, or in anticipation of, a local transmission or distribution emergency.

3. Price responsive demand response programs generally have triggers other than a called CAISO emergency, such as weather conditions or the market cost of electricity.

4. Phase 3 of R.07-01-041 is intended to determine the appropriate amount of capacity (in megawatts) to enroll in emergency-triggered demand response programs, and how to transition any excess capacity to non-emergency programs with price responsive triggers integrated with the new CAISO markets.

5. The SmartAC program and budget were approved by the Commission on February 14, 2008, in D.08-02-009, which approved a settlement agreement

among PG&E, DRA, and TURN allowing PG&E to expand its SmartAC program to approximately 305 megawatts of load reduction by June 1, 2009.

6. The following existing demand response programs are cost effective or meet other criteria for continuation during the 2009-2011 period, and should be continued: the Base Interruptible Program, the Optional Binding Mandatory Curtailment Program, the Scheduled Load Reduction Program, the Capacity Bidding Program, Critical Peak Pricing, Real Time Pricing, Technical Assistance and Technology Incentives, Emerging Markets and Technology, Automated Demand Response; SCE's Summer Discount Plan, Agricultural Pumping – Interruptible, Rotating Outage Program, and Agricultural Pump Timer Program; SDG&E's Critical Peak Pricing – Emergency, and Summer Saver programs; and PG&E's SmartAC, SmartRate, Demand Bidding Program, and PeakChoice.

7. PG&E's proposed transition of Base Interruptible Program participants into its PeakChoice does not appear to be fully developed at this time.

8. It is unclear whether PG&E can maintain the Demand Bidding Program's load impact if the Demand Bidding Program is discontinued and participants are asked to transition to PeakChoice.

9. It is likely that enrollment in and load impacts of Critical Peak Pricing tariffs will increase as they become default tariffs for certain groups of customers.

10. PG&E's PeakChoice program is new and complex, and its impacts may be difficult to analyze.

11. PG&E's administrative costs for PeakChoice program are extremely high compared to the estimated costs of incentives under the program.

12. PG&E's Business Energy Coalition Program is not cost effective, and it is extremely unlikely that this program or the proposed Automated Business

Energy Coalition Program will become cost effective over the next several years. The non-cost effectiveness criteria cited by PG&E in support of this program, such as locational value and flexibility, are not unique to the Business Energy Coalition programs, and are not sufficient to support continuation of these programs.

13. Current estimates show that the SCE Summer Discount Program is only marginally cost effective; the cost effectiveness may be improved if SCE is able to maintain enrollment in the program with a decreased budget for marketing.

14. The communications supported by the Rotating Outage Program include both Commission-mandated notices and courtesy notifications intended to facilitate the administration of emergency rotating outages.

15. SCE's Agricultural Pump Timer Program utilizes Time Management Load Control devices to allow customers to interrupt their equipment at peak times, in order to take advantage of low off-peak utility rates.

16. Critical Peak Pricing programs overall have high estimated benefit to cost ratios based on the Total Resource Cost Test.

17. Technical Assistance and Technology Incentives activities differ somewhat in participation requirements, incentive payments, and other structural aspects, but all support the installation of technologies to facilitate customer peak load reduction and demand response.

18. Technical Assistance and Technology Incentives activities facilitate peak load reduction and demand response by utility customers, and in many cases lead directly to customer enrollment in utility demand response programs.

19. Technical Assistance and Technology Incentives activities include many activities that do not result in the payment of financial incentives, but provide valuable services to customers. These services, such as conducting audits,

developing company-specific demand response plans, and recommending equipment and strategies to improve load reduction, are not true program administration activities (such as data collection or processing), and should not be considered program administration in the determination of program budgets.

20. SCE's method of reporting money spent under its Technical Assistance and Technology Incentives program makes it difficult to determine the demand for this program or the budget required to sustain it through 2011.

21. Because the Technical Assistance and Technology Incentives programs provide services to customers beyond financial incentives, such as audits, it is not appropriate to limit the budget for Technical Assistance and Technology Incentives activities to twice the financial incentives paid to customers.

22. The Emerging Markets and Technologies Programs fund research projects intended to further develop technologies and equipment, processes, and products to make demand response easier or more effective in the future.

23. It is not appropriate to give blanket approval now for long-term emerging technologies projects that cannot yet be identified.

24. Automated demand response refers to automated enabling technologies that allow a customer to reduce electricity usage in response to peak load conditions or high prices without needing to take a specific action.

25. Automated demand response activities appear to result in some load reduction, through participant enrollment in other demand response programs.

26. The utilities have not submitted any analysis of whether automated demand response programs are cost-effective on their own, separate from the underlying programs in which participants ultimately enroll.

27. Through the use of mass media such as TV commercials, radio advertisements, billboards, newspapers, and other communication avenues, Flex

Alert is intended to educate the general public about the need to reduce electricity during times of peak electricity demand.

28. A working group related to the California Energy Efficiency Strategic Plan is exploring alternatives for statewide coordination and branding for demand side awareness.

29. The challenge of keeping the power grid in balance grows as the amount of intermittent resources grows.

30. Smart Charging technology that could assist customers in keeping efficient electric or hybrid electric vehicles charged without increasing peak system load may move electricity demand away from peak times, without creating inconvenience for customers.

31. The Small Customer Load Aggregation Pilot, as proposed, is duplicative of two other proposals in PG&E's 2009-2011 demand response application.

32. It is likely that information from this pilot will enable the utility to more effectively and efficiently provide customers with Programmable Communicating Thermostats and information needed to utilize that equipment more effectively.

33. The proposed Tier Alert Pilot is designed to achieve energy conservation, and is unlikely to result in any actual demand response.

34. SDG&E's proposed residential automated controls pilot is designed to answer specific questions related to the willingness of residential customers to install enabling technologies that facilitate load reduction, as well as curtailment devices that allow the utility to control certain appliances.

35. Changes in the energy market over the next two years may affect the desirability of entering into new contracts for 2012 and beyond.

36. A properly designed baseline calculation methodology is important for the success of any demand response program as it provides the benchmark by which performance is measured.

37. Existing studies suggest there are more accurate baselines than the current three-day unadjusted baseline for the large commercial and industrial customers. The studies also conclude that a day-of adjustment based on usage data from the morning before an event can significantly reduce the bias and improve the accuracy of this type of baseline.

38. Existing studies recommend a 10-day baseline with a day-of adjustment.

39. The settlement baseline for demand response activities should be consistent across utilities and programs.

40. As dynamic tariffs become more common and the utilities implement default Critical Peak Pricing, current rules against participation in more than one demand response program or tariff may limit the amount of peak load reduction that can be achieved through demand response.

41. It is consistent with the Commission's policy of encouraging cost effective demand response activities to allow customers to participate concurrently in two demand response activities and programs, as long as duplicative payments for a single instance of load drop can be avoided.

42. It is consistent with the Commission's policy of encouraging cost effective demand response activities to allow customers receiving partial standby service from PG&E to participate in certain demand response programs for the load they purchase from the utility.

43. Participation in more than one demand response program may provide flexibility to customers and expand their ability to respond to the varying conditions that trigger demand response.

44. It is logical to continue existing permanent load shifting activities for the terms of their existing contracts.

45. Circumstances relevant to the expansion of permanent load shifting are likely to change by 2011.

46. A standard offer would enable customers to choose from any vendor that offers thermal energy storage technologies.

47. EM&V activities, which include program evaluation, load impact evaluation, and demand response research projects, are essential to the development of effective, and cost effective, demand response programs in California.

48. PG&E's request for two-way balancing account treatment for the DREBA departs from the cost recovery rules in place for that utility in 2006-2008.

49. PG&E's current one-way balancing account treatment for certain demand response expenses in DREBA allows tracking of actual expenses and recovery of those expenses up to the authorized budget level.

50. Two-way balancing account treatment for program incentives allows recovery of additional incentive costs in the unlikely event that extreme conditions result in more than the forecasted number of events through 2009-2011, without requiring additional ratepayer funding unless extreme conditions cause the incentive budget to be exeeded.

Conclusions of Law

1. It is reasonable to continue existing demand response programs that are estimated to be cost effective, or that serve the public interest in other ways.

2. It is reasonable to approve the discontinuation of a demand response activity if it does not provide actual demand response, or if the program's

participants will be transitioned to an equally effective demand response program, while maintaining their load reduction efforts.

3. It is reasonable to cap emergency triggered programs at their current enrollment (in megawatts) and funding levels pending the resolution of R.07-01-041 Phase 3.

4. It is reasonable to provide a limited exemption from the general cap on emergency triggered demand response programs for the PG&E SmartAC program, and to cap that program at the expanded enrollment level of 305 megawatts authorized and funded in D.08-02-009.

5. It is reasonable to deny PG&E's request to transition the Base Interruptible Program customers to PeakChoice because PeakChoice is unproven.

6. For most demand response activities, administrative expenses should not be greater than customer incentives paid under the program.

7. It is reasonable to approve PG&E's request to modify event notification time from 12 noon to no later than 2:00 p.m. the day preceding an event to align with CAISO markets.

8. Consistent with current Commission policy, for programs that allow customer enrollment directly through the utility as well as through a demand response aggregator, it is reasonable for directly enrolled customers to receive 80% of earned incentives, and customers enrolled through an aggregator to receive 100% of the earned incentives.

9. It is reasonable to increase tracking requirements for certain demand response activities in order to monitor performance under these programs and develop better budget forecasts for future funding cycles.

10. It is reasonable for Technical Assistance and Technology Incentives and Automated Demand Response activities available through more than one utility to have similar requirements throughout the state, including the following:

a. The maximum rebate for non-Automated Demand Response services under the utilities' Technical Assistance and Technology Incentives programs should be $125 per kilowatt for all utilities.

b. The maximum rebate for automated demand response equipment installed through Technical Assistance and Technology Incentives or Automated Demand Response Programs should be $300 per kilowatt for all utilities.

c. Customers receiving an incentive of $100 or more per kilowatt under the Technical Assistance and Technology Incentives program should be required to make a minimum one year commitment to a demand response program or Critical Peak Pricing tariff.

d. SCE and SDG&E should develop proposals for integrating their Technical Incentives programs with other, similar demand side management inventive or rebate programs and should submit detailed proposals consistent with ongoing work through the Energy Efficiency Strategic Plan workgroups as part of their next demand response program applications.

11. It is reasonable to approve activities that may be affected by ongoing working groups on coordination and integration of demand side management activities for 2009-2011, subject to further review and potential modification in A.08-07-021 et al., where they can be reviewed in the context of those coordination efforts.

12. It is reasonable to use demand response funding to support activities that will leverage the utilities' AMI investments to increase demand response.

13. It is advisable to study technologies and strategies that may assist with integration of intermittent renewables into the power grid before the electricity provided by intermittent resources increases.

14. It is reasonable to explore ways to leverage the ratepayers' investment in infrastructure such as the Smart Meter program, in an attempt to provide additional benefits beyond those foreseen when the project was approved.

15. Because it is not necessary to determine at this time whether an RFP for additional demand response contracts will be appropriate in 2011, it is reasonable to await additional information before approving an RFP request.

16. In the long term, utilities should attempt to steer customers with highly variable loads away from demand response programs that require baselines, and towards programs that do not require baseline calculation such as Critical Peak Pricing.

17. It is reasonable to consider Critical Peak Pricing to be an energy payment program for the purposes of dual program participation.

18. It is reasonable and consistent with the Commission's policy of encouraging cost effective demand response activities to allow customers to participate concurrently in two demand response activities and programs, as long as duplicative payments for a single instance of load drop can be avoided.

19. It is reasonable to allow partial standby customers to participate in these demand response programs for the load they purchase from PG&E, and we approve this request.

20. It is reasonable to approve the settlement proposed on February 23, 2009, and adopt the contracts between SCE and AER, and SCE and EnerNOC as modified under that settlement.

21. The settlement agreement between PG&E and SF Power on the Small Commercial Aggregation Pilot is reasonable in light of the whole record, consistent with the law, and in the public interest.

22. It is reasonable to defer decisions on the best method for expanding the availability of permanent load shifting until more information is available.

23. It is reasonable to approve EM&V funding associated with approved demand response programs, pilots, and related activities.

24. Because it is intended for non-controversial updates or changes to existing programs, the advice letter process is not appropriate for the review of new programs or an increase in the total budget for a program area adopted in a decision.

25. It is reasonable to provide the utilities with some flexibility to shift funds among demand response programs, in order to provide the utilities with the ability to respond effectively to unforeseen developments that may occur and to respond to changing conditions.

26. It is reasonable to allow two-way balancing account treatment for demand response program incentives.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company shall continue the following existing demand response programs, as described in this decision: the Base Interruptible Program, the Optional Binding Mandatory Curtailment Program, the Scheduled Load Reduction Program, the Demand Bidding Program, the Capacity Bidding Program, Critical Peak Pricing, Real Time Pricing, Technical Assistance and Technology Incentives, Emerging Markets and Technology, Automated Demand Response, the Summer Discount Plan, Agricultural Pumping – Interruptible, Rotating Outage Program, and the Agricultural Pump Timer Program.

2. Southern California Edison Company's proposal to implement an Energy Options program is approved. Southern California Edison Company shall transition participants in its Demand Bidding Program and Capacity Bidding Program into this program, as proposed, and shall discontinue those programs when the transition is complete.

3. Pacific Gas and Electric Company shall continue the following existing demand response programs, as described in this decision: the Base Interruptible Program, the Optional Binding Mandatory Curtailment Program, the Scheduled Load Reduction Program, the Demand Bidding Program, the Capacity Bidding Program, Critical Peak Pricing, Real Time Pricing, Technical Assistance and Technology Incentives, Emerging Markets and Technology, Automated Demand Response, SmartAC, SmartRate, and PeakChoice.

4. San Diego Gas & Electric Company shall continue the following existing demand response programs, as described in this decision: the Base Interruptible Program, the Optional Binding Mandatory Curtailment Program, the Scheduled

Load Reduction Program, the Demand Bidding Program, the Capacity Bidding Program, Critical Peak Pricing, Real Time Pricing, Technical Assistance and Technology Incentives, Emerging Markets and Technology, Automated Demand Response, Critical Peak Pricing – Emergency, and Summer Saver programs.

5. San Diego Gas & Electric Company shall transition its Demand Bidding Program participants onto its Critical Peak Pricing Tariff, as proposed, and shall discontinue the Demand Bidding Program when the transition is complete.

6. Pacific Gas and Electric Company shall discontinue the Base Interruptibles Program Option B within 30 days of the effective date of this decision.

7. Pacific Gas and Electric Company shall discontinue the Business Energy Coalition and the Automated Business Energy Coalition within 90 days of the effective date of this decision.

8. San Diego Gas & Electric Company shall discontinue its Peak Day Credit Program within 30 days of the effective date of this decision.

9. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall provide customers currently enrolled in discontinued programs with timely notice of the programs' cancellation, as well as information on other demand response program options for which the customer may be eligible.

10. The demand response budgets for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company enumerated in Section 24 of this decision are adopted for 2009-2011.

11. All emergency-triggered demand response programs of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are capped at their current level of enrolled megawatts, and shall not be expanded, pending a decision in Phase 3 of Rulemaking 07-01-041.

PG&E's SmartAC program is exempted from this cap and shall continue to enroll customers consistent with the Commission's direction in D.08-02-009.

12. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall modify their Technical Assistance and Technology Incentives programs as follows. These rules shall apply to customers receiving services under these programs beginning January 1, 2010:

a. The maximum rebate or incentive for non-Automated Demand Response services under the utilities' Technical Assistance and Technology Incentives programs should be $125 per kilowatt for all utilities.

b. The maximum rebate or incentive for automated demand response equipment installed through Technical Assistance and Technology Incentives or Automated Demand Response Programs should be $300 per kilowatt for all utilities.

c. Customers receiving an incentive of $100 or more per kilowatt shall be required to make a minimum one year commitment to a demand response program or Critical Peak Pricing tariff.

13. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall develop proposals for integrating their Technical Incentives programs with other, similar demand side management incentive or rebate programs, consistent with the discussion in Section 12 of this decision. Each utility shall submit a report on how to integrate these activities, consistent with the results of the Energy Efficiency Strategic Plan workgroups, as part of their next demand response program applications.

14. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall each provide annual reports on their Emerging Markets and Technology projects, including estimates of the expected

term of each project, to Energy Division as described in Section 12 of this decision. These utilities shall work with Energy Division staff to develop a reporting format, and shall provide reports on the previous year's Emerging Markets and Technology activities reports on the director of the Commission's Energy Division, and to provide copies to the most recent service list in this proceeding. In addition, the utilities shall post their monthly reports on a publicly available web site.

15. Utilities shall evaluate the results of their Automated Demand Response activities as described in Section 12. 3, above. The utilities shall report the results of these evaluations to the Energy Division Director by September 30, 2010, and provide copies to the most recent service list in this proceeding. In addition, the utilities shall post these reports on a publicly available web site. The utilities shall jointly hold two workshops on these results, one to present and discuss their findings and solicit feedback from the parties and a second public workshop to present proposals based on the results of the first workshop and solicit feedback and other proposals from the parties. The timing of these workshops shall be coordinated with other workshops planned by the DRMEC.

16. To continue beyond December 31, 2011, an Emerging Markets and Technology Project funded through the 2009-2011 budgets adopted in this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each request permission either through a Tier 2 advice letter describing specific projects and the reason for the project to continue beyond the end of the funding period, or by including a request to continue these projects in their next demand response funding application.

17. The Flex Alert Campaign shall continue at the requested funding levels, as set forth in Section 13, above, pending final recommendations of the California Energy Efficiency Strategic Plan on coordination of statewide education efforts.

18. The utilities' proposed specialized marketing activities and budgets are approved for 2009-2011, subject to further review and potential modification in Application 08-07-021 et al., the ongoing energy efficiency applications proceeding.

19. Pacific Gas and Electric Company's requests to issue a Request for Proposal in 2011 to solicit more demand response contracts for the 2012-2014 period are denied.

20. The settlement on Southern California Edison Company's proposed aggregator contracts with Alternative Energy Resources, Inc. and EnerNOC Inc., contained in Attachment A of this decision, is approved.

21. The settlement between Pacific Gas and Electric Company and SF Power on the Small Commercial Aggregation Pilot, contained in Attachment B of this decision, is approved.

22. The following demand response pilots are approved to operate during 2010 and 2011, along with pilots already approved in D.08-12-038:

a. For Pacific Gas and Electric Company: the Commercial and Industrial Intermittent Resource Pilot and the Hybrid Electric Vehicle/Electric Vehicle Smart Charging Pilot.

b. For Southern California Edison Company: the Smart Thermostat Customer Experience Pilot and the Optional Programmable Communicating Thermostat Pilot.

c. For San Diego Gas & Electric Company: the Residential Automated Controls Pilot.

23. The Tier Alert Pilot proposed by Southern California Edison Company and the Small Customer Load Aggregation Pilot proposed by Pacific Gas and Electric Company are rejected.

24. The plans proposed by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to transition demand response activities to integrate into the new CAISO markets during 2009-2011 are approved with the following modifications. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each prepare two related reports over the next two years. Each company shall serve each report on the director of the Commission's Energy Division, and to provide copies to the most recent service list in this proceeding. In addition, the utilities shall post these reports on a publicly available web site by the date indicated. These required reports are:

a. An evaluation of the Participating Load pilots in 2009. This report shall assess what was learned through the pilots, areas that need further exploration (if any), and potential next steps for 2010 and beyond. Each of the utilities shall provide this report by December 31, 2009.

b. A report on the transition of demand response programs into Market Redesign and Technology Upgrade. This report shall include lessons learned from the utilities' 2009 pilots and their 2010 Proxy Demand Resource experience, including performance assessments as well as an evaluation of expected costs and benefits of integrating of all programs into Proxy Demand Resource (if such programs have not already been integrated) and Participating Load (for all programs). Each of the utilities shall provide this report by January 31, 2011.

25. Within 30 days of the filing of CAISO's Proxy Demand Resource tariff with the Federal Energy Regulatory Commission, the utilities shall propose

modifications to one or more existing demand response programs that will make at least 10 percent of the megawatts enrolled in the demand response programs authorized in this decision comply with the requirements of CAISO's Proxy Demand Resource.

26. Within 30 days of the approval of CAISO's Proxy Demand Resource tariff by the Federal Energy Regulatory Commission, each utility shall file a proposal with the Commission to make at least one new or existing demand response program or option within a program comply with the 10-minute dispatch notification time requirements for participation in the CAISO's ancillary services market as either Proxy Demand Resource or Participating Load.

27. All demand response programs that have not been transitioned to Proxy Demand Resource or Participating Load shall be scheduled in the CAISO day-ahead market as Non-participating Load, complying with CAISO requirements for scheduling including the provision of a price curve.

28. All demand response programs of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company utilizing a baseline for settlement purposes shall use a 10-day individual customer baseline with a day-of adjustment, as described in Section 17 of this decision. The adjustment shall be symmetrical (upward or downward, as indicated by usage in the window time period), shall be capped at 20% of the calculated average usage, and shall be based on the first three of the four hours prior to the event. Each of these utilities shall offer customers the opportunity to opt into the adjustment.

29. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each work with parties to develop a definition of highly variable load customers, and to prepare a report containing

that definition along with an estimate of the number of highly variable load customers currently in its baseline demand response programs, and the number of megawatts contributed to the programs by those customers. The report shall propose a plan for steering highly variable load customers towards demand response programs that do not require baseline calculations for settlement purposes. This report shall also include information on the proportion of customers choosing the morning-of adjustment option that reach or exceed the maximum adjustment of 20%, and how often that maximum adjustment is reached. Each of the utilities shall submit its report to the Director of the Energy Division no later than September 1, 2010 and provide copies to the most recent service in these proceedings.

30. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file Tier Two advice letters within 90 days of the effective date of this decision specifying dual program participation rules consistent with the discussion in Section 18 of this decision. These rules shall allow customers to participate concurrently in up to two demand response activities, if one provides energy payments and the other provides capacity payments. These rules shall prohibit concurrent participation in programs with the same trigger (day-ahead or day-of); however, a participant may participate in one day-ahead and one day-of program. In the case of simultaneous or overlapping events called in two programs, a single customer enrolled in those two programs shall receive payment only under the capacity program, not for the simultaneous event for the energy payment program. Critical Peak Pricing shall be considered to provide an energy payment for the purposes of these dual program participation rules. These rules shall also apply

to customers enrolled in a utility-administered program and customers administered by a third-party aggregator.

31. Pacific Gas and Electric Company shall allow partial standby customers to participate in the following demand response programs for the load they purchase from the utility: the Demand Bidding Program, the Base Interruptible Program, the Aggregator Managed Portfolio, the Capacity Bidding Program, Critical Peak Pricing, and the PeakChoice Program.

32. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall work with parties to examine ways of expanding the availability of permanent load shifting. This study shall include discussion of a standard offer proposal that could apply generally to any permanent load shifting technologies including, but not limited to, thermal energy storage. This study should also consider other ways of encouraging permanent load shifting, including modifications to time of use rates or another RFP process. This report shall contain a summary of permanent load shifting standard offers available throughout the United States, as well as an evaluation of what incentive payment would be appropriate for a future standard offer. Each of the utilities shall provide its report to the Director of the Energy Division no later than December 1, 2010, and shall provide copies to the most recent service list in this proceeding. In addition, the utilities shall post these reports on a publicly available web site.

33. During the 2009-2011 period, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may file a petition for modification of this decision to request to develop new demand response programs or program options, or to request additional funding beyond the total amount approved in this decision. During this period, these utilities

may request new demand response programs only through a new application. During this period, these utilities may request changes to policies specifically adopted in this decision, such as the calculation of a settlement baseline for an existing program or rules for concurrent participation in multiple programs, and modifications to existing aggregator contracts through either an application or a petition for modification of this decision.

34. During the 2009-2011 period, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may request to change program terms and conditions via a Tier 2 advice letter.

35. The following rules for fund shifting are adopted for the 2009-2011 demand response programs of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company:

a. The utilities may shift up to 50% of a program's funds to another program within the same budget category. The utilities shall document the amount of and reason for each shift in their monthly demand response reports.

b. The utilities may file a Tier 2 advice letter to request elimination of a program. No program may be eliminated through multiple fund shifting events or for any other reason without prior authorization from the Commission.

c. The utilities shall file a Type 2 advice letter to request authorization to shift more than 50% of a program's funds to a different program within the same budget category. If a shift of more then 50% of a program's funds is proposed as part of the implementation of a new program, the utility shall include the proposed fund shift in its application for approval for the new program, described in Ordering Paragraph 27.

d. The utilities shall not shift funds among the 10 categories defined in the table in Section 26 of this decision.

36. Consistent with the determinations made in this decision, the budgets specified in Section 24 of this decision are adopted for the demand response activities for 2009-2011 of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. These budgets include the amounts adopted for bridge funding for 2009 in Decision 08-12-038.

37. PG&E shall revise its Demand Response Expense Balancing Account to allow two-way balancing account treatment for program incentives only. Administrative expenses for demand response programs will continue to be subject to one-way balancing account treatment, and are capped at 50% of the program costs for each approved program, as provided in this decision.

38. The Demand Response Measurement and Evaluation Committee shall continue its oversight of demand response evaluation, measurement and verifications activities. Beginning with the evaluation of 2009 demand response programs, the Demand Response Measurement and Evaluation Committee shall oversee not only the evaluation of statewide demand response activities, but also the evaluation of activities conducted by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company. In addition, the Demand Response Measurement and Evaluation Committee shall conduct an annual public workshop presenting the results of demand response evaluations conducted under the Demand Response Measurement and Evaluation Committee's oversight. This annual workshop shall be noticed to the most recent service list of this proceeding.

39. Starting with a year-end report for 2009, and continuing through the end of the current budget period, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall prepare and provide monthly reports consistent with the discussion in Section 28

of this decision. The utilities shall use a consistent monthly report format approved by Energy Division staff, and shall provide these monthly reports to the Director of the Commission's Energy Division, with service on and the most recent service list in this proceeding. In addition, the utilities shall post their monthly reports on a publicly available web site. The year-end report for 2009 shall be provided no later than January 21, 2010, with subsequent reports provided monthly thereafter.

40. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall implement the modifications to policies and program rules affecting existing demand response programs adopted in this decision by January 1, 2010, or upon Energy Division approval of the advice letter implementing the change. The utilities shall implement the new programs and pilots authorized in Sections 10, 11, 12, and 14 of this decision in 2010, unless otherwise noted in this decision. Southern California Edison Company, San Diego Gas & Electric Company, and Pacific Gas and Electric Company shall each file one or more Tier 1 compliance advice letters within 90 days of the date of the effective date of this decision updating its tariffs to be consistent with the requirements of this decision and specifying the date on which those changes will take effect.

41. The utilities' applications for the 2012-2014 period shall be filed by January 30, 2011.

42. Application (A.) 08-06-001, A.08-06-002 and A.08-06-003 are closed.

This order is effective today.

Dated August 20, 2009, at San Francisco, California.

MICHAEL R. PEEVEY

President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners