Decision 14-05-025 May 15, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011 (Filed September 19, 2013)

DECISION APPROVING DEMAND RESPONSE PROGRAM IMPROVEMENTS AND 2015-2016 BRIDGE FUNDING BUDGET

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DECISION APPROVING DEMAND RESPONSE PROGRAM IMPROVEMENTS AND 2015-2016 BRIDGE FUNDING BUDGET

1. Summary

This decision approves certain programs and activities for Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company's demand response programs during 2015 and 2016. As indicated in Decision 14-01-004, the decision approving two years of bridge funding, today's decision also authorizes specific budgets in order to administer the demand response programs approved here. Pacific Gas and Electric Company is authorized a budget of $100,673,133 for demand response programs during bridge fund years 2015-2016. San Diego Gas & Electric Company is authorized a budget of $39,872,607 for demand response programs during bridge fund years 2015-2016. Southern California Edison Company is authorized a budget of $172,307,062 for demand response programs during bridge fund years 2015-2016.

Rulemaking 13-09-011 remains open to address Phases Two through Four, Phase One of the proceeding is closed.

2. Background

The California Public Utilities Commission (Commission) initiated Rulemaking (R.) 13-09-011 in order to enhance the role of demand response programs in meeting the state's long term clean energy goals while maintaining system and local reliability. The Order Instituting Rulemaking (OIR) recognized that completion of this proceeding would not occur prior to the filing deadline for new demand response program applications. Decision (D.) 14-01-004 approved 2015-2016 bridge funding for the demand response programs capped at 2013-2014 budget amounts.[1] Acknowledging that it also would be practical to revise the programs on a narrow basis to improve their success, D.14-01-004 required Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the Utilities) to file proposals for such program improvements.

On January 31, 2014, the assigned Commissioner and Administrative Law Judge (ALJ) issued a joint Ruling providing guidance to the Utilities (Guidance Ruling) regarding 2015-2016 demand response program improvement proposals. The Guidance Ruling directed that all proposals meet the following requirements:

- Proposals must either improve program performance or increase the availability or flexibility of a demand response program;
- Proposals may focus on design features or operational, coordination or communication practices but must contain supporting rationale based on data;
- Proposals are limited financially to the 2013-2014 budget cap;
- If proposed improvements make any changes to cost-effectiveness inputs, proposals must include a revised cost-effectiveness analyses pursuant to D.12-04-045; and
- Program revisions shall be implementable within 90 days and must be implemented no later than December 31, 2014.

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[1] The 2013-2014 budget caps are based on the budgets approved by the Commission in D.12-04-045, D.13-01-024, and D.13-04-017

On March 3, 2014, the following parties filed demand response program improvement proposals: California Energy Storage Alliance (CESA); Alarm.com and EnergyHub (jointly, EnergyHub); EnerNOC, Inc., Johnson Controls, Inc., and Comverge, Inc., (jointly, the Joint Demand Response Parties); Marin Clean Energy (MCE); Office of Ratepayer Advocates (ORA); Olivine, Inc. (Olivine); PG&E; SDG&E; SCE; and Southern California Regional Energy Network and the San Francisco Bay Area Regional Energy Network (jointly, RENs). California Large Energy Consumers Association; Direct Access Customer Coalition/Alliance for Retail Energy Markets (DACC/AReM); Joint Demand Response Parties, ORA, Olivine, PG&E, SDG&E, and SCE filed replies to the proposals on March 13, 2014.

3. Discussion

3.1. Summary

In D.14-01-004, we approved two years of bridge funding for demand response programs and activities in order to provide the Commission with adequate time to meet its goals for R.13-09-011 while ensuring continuity of current demand response programs. Bridge funding typically allows programs to continue, with the same activities and budget, for a short and specific period of time. Approval of bridge funding allows the Commission, the Utilities and other stakeholders to focus their time and effort on the Rulemaking instead of a 12-month application process. Furthermore, in D.14-01-004, we explained that the Commission did not find it prudent to spend time and resources planning for programs that may not fit into a future demand response program design.[2]

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[2] D.14-01-004 at 7.

However, the Commission did agree that it is "practical" to revise programs to improve their success, but on a narrow basis so that revisions can be implemented by 2015.[3]

In the Guidance Ruling, we reiterated the need to revise the programs on a narrow basis. Hence, the requirements in the Guidance Ruling define the boundaries of recommended program revisions so that the Commission's review of the proposals would be efficient.

In reviewing the demand response program proposals, we first considered the requirements described the Guidance Ruling. Those proposals that do not meet the requirements are listed in Table 1 and are not approved. The proposals that met the Guidance Ruling requirements are separated into four categories and reviewed: 1) the proposals pertaining to two or more utilities, including the staff proposed pilots; 2) proposals pertaining to PG&E; 3) proposals pertaining to SDG&E; and 4) proposals pertaining to SCE. We separately discuss each of these below.

In addition to proposed program improvements, we consider two other requests by the parties. First, DACC/AReM request that the Commission consider any cost allocation and cost recovery determinations made in Phase Two of this proceeding applicable to the bridge years of 2015 and 2016.[4] We confirm that changes to the cost allocation and cost recovery methodology are not in the scope of this phase of the proceeding. Again, the purpose of bridge funding is to allow programs and activities to continue, as is, so that the Commission can focus on the other issues in this proceeding. As laid out in the

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[3] *Id*. at 8.

[4] DACC/AReM Reply at 3-4.

Scoping Memo, cost allocation and cost recovery issues will be addressed in Phase Two of this proceeding.[5] Hence, it is reasonable that no determination of cost recovery changes will be made in this decision or in this phase of the proceeding.

Second, in response to the request by ORA and SCE to take more time to build a record for this phase of the proceeding, we reiterate that the Commission previously determined in D.14-01-004 that the program improvements should be on a narrow basis so as to enable implementation by 2015.[6] Furthermore, D.14-01-004 cautioned parties that disputed facts may not allow recommended revisions to meet the requirements of speedy implementation.[7] For these reasons, we deny the request to take additional time for this phase of the proceeding.

3.2. Proposals Not Meeting the Guidelines

Proposals not meeting the guidelines are listed below in Table 1. As described further below, these proposals are denied.

TABLE 1

PROPOSALS NOT MEETING THE REQUIREMENTS

PARTY	DEMAND RESPONSE PROGRAM PROPOSAL
CESA	Extend PLS[8] Program through 2020 at $32M/year.
CESA	Reduce PLS Feasibility Study Requirements for Peak Load

[5] Scoping Memo at 9.

[6] D.14-01-004 at Finding of Fact No. 7.

[7] *Id.* at 9-10.

[8] Permanent Load Shifting (PLS) is a statewide program to reduce system peak load by shifting electricity from on-peak to off-peak periods on a recurring basis. PLS often involves energy storage.

TABLE 1

PROPOSALS NOT MEETING THE REQUIREMENTS

PARTY	DEMAND RESPONSE PROGRAM PROPOSAL
	Reducing Programs.
CESA	Ease PLS EM&V[9] requirements.
CESA	Revise PLS payment structure to resemble SGIP.[10]
CESA	Change conversion factor calculations for existing buildings in PLS.
EnergyHub	Extend CBP[11] to residential customers.
EnergyHub	Allow customers to enroll in AC Cycling[12] using their own thermostat or load-control device.
EnergyHub	Focus pilot programs on residential customers and adoption of load management technologies that leverage advanced metering technology.
RENs	Allocate $0.5M from SCE's budget to implement a public agency technical support program to augment demand response services provided by SCE.

[9] EM&V or Evaluation, Measurement and Validation, also referred to as Measurement and Evaluation (M&E).

[10] Self-Generation Incentive Program (SGIP) provides incentives to support existing, new, and emerging distributed energy resources.

[11] Capacity Bidding Program is a flexible bidding program offering qualified businesses payments for agreeing to reduce their load when a CBP event is called. Some CBP programs are administered by third parties also known as demand response providers or aggregators.

[12] In Air Conditioning (AC) Cycling programs, customers allow the utility to control, or cycle, their AC units through a direct load control device on each AC unit on select summer days, in exchange for payment or bill credit.

CESA requests the Commission to extend the PLS program through 2020 at a budget of $32 million per year, reduce the feasibility requirements, ease EM&V requirements, revise the payment structure to resemble SGIP, and change conversion factor calculations for existing buildings. These proposals fail to meet the requirements of the Guidance Ruling for several reasons. First, extending the PLS program through 2020 is outside the scope of this phase of the proceeding; the Scoping Memo only envisioned one or two years of bridge funding. Furthermore, the Commission has already determined that bridge funding is limited to 2015 and 2016.[13] Second, the Commission has also determined that funding is capped at 2013-2014 levels.[14] The requested budget exceeds the cap. Third, CESA failed to provide any "supporting rationale based on analyses, studies or reports."[15] Furthermore, for CESA's proposed changes regarding feasibility study requirements, incentive payment structure, and conversion factors, CESA should follow the program modification process already in place as approved by the Commission through SCE Advice Letter 2913-E. We, therefore, find the requested changes to the PLS programs not to be reasonable. For all of the reasons described above, we deny the requests by CESA to approve changes to the PLS programs during the 2015-2016 demand response bridge fund.

EnergyHub's proposals include extending CBP to residential customers, allowing AC Cycling customers to use their own devices, and focusing the proposed pilots on residential customers using load management technologies.

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[13] D.14-02-004 at Ordering Paragraph No. 1.

[14] *Ibid*.

[15] Guidance Ruling at 3.

We deny these proposals because they lack the required "supporting rationale based on analyses, studies or reports."[16] SCE contends that extending CBP to residential customers would increase the budget and require a revised cost-effectiveness analysis.[17] We disagree because the CBP is an aggregator-managed program and any additional costs would be borne by the aggregator. However, EnergyHub provides no analysis that demonstrates an improvement to the program. EnergyHub also provides no analyses regarding its requests to allow AC Cycling customers to use their own devices. Furthermore, as SDG&E contends, the proposed enabling technology pilots are duplicative of past pilots.[18] For these reasons, we deny the revisions to the CBP, AC Cycling program and pilots, as proposed by EnergyHub for 2015-2016 demand response bridge funding. We encourage EnergyHub to recommend similar proposals in future budget application proceedings, with more vigorous analysis.

RENs' proposal recommends allocating $0.5 million from SCE's budget to implement a public agency technical support program in order to augment demand response services provided by SCE. RENs provides no "supporting rationale based on analyses, studies or reports."[19] Furthermore, as SCE states, the proposal "closely resembles program objectives in integrated demand side management" and should be addressed in the energy efficiency proceeding.[20]

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[16] Guidance Ruling at 3.

[17] SCE Reply at 5-6.

[18] SDG&E Reply at 6.

[19] Guidance Ruling at 3.

[20] SCE Reply at 9.

For these reasons, we find the RENs' proposal not to be reasonable. Thus, we deny the proposal by RENs to approve a public agency technical support program for the 2015-2016 demand response bridge funding. However, we are intrigued by the energy efficiency technical support program and encourage RENS to provide updates on the progress of its energy efficiency program.

3.3. Proposals Involving Two or More Utilities

There are five proposals involving two or more Utilities, as briefly described in Table 2.

TABLE 2

PROPOSALS INVOLVING TWO OR MORE UTILITIES

PARTY	DEMAND RESPONSE PROGRAM PROPOSAL
MCE	Improve participation in the IRM2[21] pilot by expanding the programs in which MCE customers may participate; allow MCE to administer the programs.
MCE	Expand IRM2 pilot to provide MCE AMI[22] access to real time usage data and two way communications to analyze the potential for: 1) lower cost metering and telemetry solutions; 2) aggregate demand response participation across multiple sub-load aggregation points; and 3) residential automated demand response.
MCE	Revise incentive structure for IRM2 pilot to allow CCA[23] customers to not have to choose between participating in a CCA or in demand response.

21 Intermittent Resource Management Pilot Phase Two (IRM2) – an early stage training vehicle to give demand response providers experience in the California Independent System Operator (CAISO) energy markets.

22 Advanced Metering Infrastructure.

23 Community Choice Aggregation.

TABLE 2

PROPOSALS INVOLVING TWO OR MORE UTILITIES

PARTY	DEMAND RESPONSE PROGRAM PROPOSAL
MCE	Extend schedule for establishing 2014-2015 pilots to allow for development of a CCA-run pilot.
ORA	Revise trigger for BIP[24] to an earlier step in the CAISO process.
ORA	Require accurate marketing for residential TOU,[25] consider combining marketing and outreach for TOU with Peak Time Rebate.[26]
ORA	Require reporting of Utilities' dispatch decision-making process.
Olivine	Revise the IRM2 to: 1) be statewide; 2) allow for third party access; 3) include a methodology that captures program capabilities not captured elsewhere; 4) provide a default demand response provider for those without another option; and 5) provide a mechanism to incorporate resources that may not fit into current programs.
PG&E	Determine that the staff proposed behavior pilot is duplicative of current pilots.
SDG&E	Determine that the staff proposed pilots are redundant and inefficient.

We first address the three proposals from ORA.

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[24] Base Interruptible Programs provides commercial customers incentives to reduce their facility's load to or below a customer-selected level. Penalties apply for non-compliance.

[25] Time of Use Rates are higher when electric demand is higher.

[26] Peak Time Rebate provides rebates to customers who lower their electricity consumption during times of especially high system demand.

3.3.1. ORA's Proposals Regarding BIP, TOU and Additional Reporting Requirements

ORA filed the following three proposals affecting all three of the Utilities:

- a proposal for improvements to the BIP program;
- a proposal to require accurate marketing for residential TOU; and
- a proposal to require the three Utilities to provide additional reports that identify when demand response programs are economic but not dispatched.

For the reasons explained below, we deny the proposals regarding BIP and TOU marketing, but approve the new reporting requirements, with modifications.

First, ORA recommends that the Commission approve changing the BIP dispatch order to avoid excessive and expensive non-resource adequacy procurement. Currently the California Independent System Operator's (CAISO's) Operating Procedure 4420 places BIP second to last in its dispatch order.[27] ORA explains that, pursuant to the terms of a Settlement,[28] BIP can only be used after the CAISO has used all other resources in its balancing authority. ORA contends that because BIP is a resource adequacy resource that is already paid for by ratepayers, the CAISO should be able to use BIP before procuring non-resource adequacy resources within the CAISO's own balancing authority. ORA recommends that BIP be moved to an earlier step in the CAISO Operating

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[27] ORA Proposal at 10, Footnote No. 21 citing CAISO Operating Procedure 4420.

[28] ORA explains that the Commission adopted a Reliability-Based Demand Response Settlement in D.10-06-034 (Settlement) where parties developed a wholesale reliability demand response product (RDRP) compatible with the Utilities' reliability-based demand response programs. The Settlement provided that CAISO would develop the rules for RDRP through a collaborative stakeholder process.

Procedure 4420 so that ratepayers do not pay twice for the same capacity BIP is intended to provide, thus improving its cost-effectiveness.[29]

In opposition to ORA's BIP proposal, PG&E claims that the proposal is unnecessary because the CAISO already has the ability to dispatch BIP at any step of Operating Procedure 4420.[30] PG&E states that ORA's list of Exceptional Dispatch provides no explanation of why BIP would have been a good resource to use instead.[31] Furthermore, PG&E argues that ORA's assertion that BIP could have been used as an alternative to Exceptional Dispatch is speculative and untested.[32] Similarly, CLECA contends that ORA's assertions must be evaluated in evidentiary hearings, to which ORA requests the Commission to allow more time to build a record for program improvements.[33] While agreeing that the Commission should deny ORA's proposal, SCE recommends that the entire settlement regarding BIP be renegotiated because the settlement trigger did not consider this consequence.

We find that changes in CAISO's Operating Procedure, as recommended by ORA, could harm the Settlement. In comments to the proposed decision, ORA argues that because this requested change is for 2015 and beyond, the adoption of such a change would not violate the terms of the Settlement.[34]

[29] ORA alleges that ratepayers pay for BIP through its program costs and again through Exceptional Dispatch procurement of non-resource adequacy resources.

[30] PG&E Reply at 7.

[31] *Ibid*.

[32] *Id*. at 8.

[33] We previously determined that we would not consider spending additional time on building a record for Phase One, when a purpose of bridge funding is to save time.

[34] ORA Comments to Proposed Decision at 3.

However, in order for such changes to take place, all parties to the Settlement must be in agreement. Because not all parties are in agreement, it is not reasonable for the Commission to adopt changes in the BIP dispatch order. We deny ORA's request to change the BIP dispatch order at this time.

Second, ORA proposed that the Commission require the Utilities to focus residential TOU marketing to ensure that the advertising does not mislead the customer and lead to increased customer opt-outs. With both SCE and SDG&E proposing opt-in TOU within the next year, ORA is concerned that marketing be performed so as not to mislead customers into thinking that TOU rates will lead to lower bills. ORA recommends that TOU rate marketing should focus on educating customers about the potential impacts of a rate change and provide customers the ability to monitor usage patterns and compare tiered and TOU rates.

PG&E contends that ORA's proposal is outside the scope of this proceeding since the guidance for the 2012-2014 demand response applications stated that the proceeding's focus did not include dynamic rates and that the authority to develop and recover costs associated with dynamic rates would be addressed in other proceeding.[35] SDG&E agrees with the needs expressed by ORA but contends that the need has been met by marketing approaches already proposed by SDG&E.[36]

We disagree with PG&E's assertion that dynamic rates should not be addressed in this proceeding. The Commission addressed dynamic rates and

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[35] PG&E Reply at 6. *See* also Footnote 10.

[36] SG&E Reply at 4-5.

marketing of such rates throughout D.12-04-045.[37] However, while we agree in principle with ORA's proposal, we find that it lacks specificity. Furthermore, we find that Commission rules already provide for the aspects of ORA's proposals that would prohibit misleading marketing. Finally, we note that the Commission has an open proceeding on dynamic rates where this aspect may also be addressed in more depth.[38] Thus, for all the reasons described above, we find ORA's proposal regarding TOU marketing to be unnecessary. We, therefore, deny this proposal.

Third, ORA requested that the Commission require the Utilities to provide weekly exception reporting to Energy Division and ORA. As proposed by ORA, the report would identify and describe each occurrence when a demand response program was economic to dispatch but the utility decided to utilize a non-demand response resource instead. ORA lists all the requirements of this new report and states that the new report will allow for transparency and increased knowledge by the Commission of any needed mid-season revisions.[39]

SCE contends that ORA's proposed reporting requirements are duplicative of current demand response reporting and are already included in the SCE's annual least-cost dispatch report.[40] SDG&E supports greater transparency and considers ORA's request to be reasonable as long as confidentiality is

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37 D.12-04-045 at 82-92 and 133-138.

38 R.12-06-012, the Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations.

39 ORA Response at 8.

40 SCE Reply at 6.

maintained.[41] PG&E also supports the proposal and its claim of increased transparency. However, PG&E cautions that some of the requested information may not be available.[42] PG&E suggests that new or additional reporting requirements be developed in an open manner with input by all parties and is considered in context with other reporting requirements.

We agree that the additional reporting requested by ORA will provide transparency. We find the request by ORA for additional reporting to be reasonable. However, we agree with the Utilities' concerns regarding confidentiality and duplication. Therefore, we adopt the proposal with the following caveats. Within 30 days from the issuance of this decision, the Utilities shall organize and meet with the appropriate Commission Staff, ORA, and all other interested stakeholders, to develop an agreed-upon reporting template using the draft reporting template in Appendix A, as a starting point. All stakeholders should take into consideration other utility reporting requirements to ensure no duplication. Furthermore, we require that confidentiality, with respect to aggregator or customer data, is maintained in the event of any public release of the data. Finally, within 30 days following that meeting, the Utilities shall file a Tier One Advice Letter requesting approval of the final reporting template.

In comments to the proposed decisions, parties recommended several revisions to the new reporting requirements. SDG&E contends that the weekly reporting is burdensome and requests revising the requirement to monthly

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41 SDG&E Reply at 1-2.

42 PG&E Reply at 10.

reporting. Furthermore, SDG&E requests that more time be provided to come to a consensus on the template.

We find the following to be reasonable and adopt them:

a) Commission staff shall host a lessons-learned workshop regarding the new reporting requirements.[43] The workshop shall be held no later than December 31, 2014.

b) The Base Interruptible Program and the Agricultural Pumping Program are emergency responsive programs and should be excluded from this reporting requirement[44] and

c) As described above, confidentiality of data shall be protected according to the law.[45]

3.3.2. Staff Proposed Pilots

In the OIR, the Commission introduced three staff-proposed pilots: IRM2 Enhancement in Northern California, IRM2 Enhancement in Southern California, and a pilot to increase customer responsiveness to dynamic electricity rates. As discussed further below, we find the IRM2 in Southern California to be duplicative and unnecessary at this time. We also decline to approve the customer responsiveness pilot due to duplication with current and past efforts. While we find the Northern California IRM2 Enhancement to have value, it has not gained interest from potential participants and, thus, we look to PG&E's Supply Side pilot to assist the utilities in gaining further experience and

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[43] SCE Comments to the Proposed Decision at 4-6.

[44] *Ibid*.

[45] Ibid. See also Joint Demand Response Parties Comments to the Proposed Decision at 2-3.

knowledge with the CAISO energy markets. We first address the customer responsiveness pilot and then the two IRM2 pilots.

3.3.2.1. Customer Responsiveness Pilot (Behavior Study)

Staff proposed the customer responsiveness pilot in the OIR with the goals of: 1) increasing TOU and CPP customer awareness to know when peak periods are occurring; and 2) using feedback and social norms to encourage behavior change. A third goal of the pilot, specific to CPP customers, is introducing automated technology to better understand how the first two goals work in concert.

All three Utilities provide facts that the customer responsiveness pilot is duplicative of other past or current activities. For example, PG&E states that D.10-02-032 approved metrics and a reporting process to track customer understanding of the SmartRate and Peak Day Pricing programs.[46] Furthermore, PG&E notes that in its 2014 general rate case, it requested funding for maintenance of Peak Day Pricing customers to support them after they have transitioned to their new dynamic rate.[47] SCE contends that existing demand response activities in existing demand response pilots and programs could be leveraged to achieve the same objectives as the pilot rather than create new tasks.[48] SDG&E supports the staff proposed behavior pilot, but notes that behavior-based programs are part of SDG&E's Integrated Demand Side

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[46] PG&E Response to OIR at 6-7 citing D.10-02-032 at Ordering Paragraph No. 15.

[47] *Id* at 7.

[48] SCE Response to OIR at 4.

Management programs and are under the oversight of the Energy Efficiency Program.[49, 50]

Additionally, The Utility Reform Network (TURN) questions the need for "incremental funding to support these activities, which should be funded through the various existing funding streams for customer outreach and education."[51] TURN provides a list of examples of such funding streams.[52]

We agree that the pilot is duplicative of other past and current similar efforts. Accordingly, approving the pilot would be an inefficient use of ratepayer funds. Thus, we deny the behavior-based pilot.

3.3.2.2. Continuations to IRM2 Pilot

In the OIR, Staff proposed two pilots presented as continuations to the IRM2: the IRM2 Enhancement to Northern California, proposed to build expertise with direct CAISO engagement among certain third-party participants and the IRM2 in Southern California, proposed to address the lack of understanding and experience of bidding demand response into the CAISO energy market in the Southern California region. Staff alleges that there is a learning gap by third parties who may want to build this capacity internally. As such, the goal of the IRM2 Enhancement pilot is to enable these parties to stand alone as direct participants in the CAISO market, independent of the Utilities or

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49 SDG&E Proposals at 31.

50 In its reply to proposals, ORA questions why SDG&E has separate behavior based programs when all demand response program depend upon a customer's behavior. We do not consider this in the scope of this proceeding.

51 TURN Response to OIR at 8.

52 See TURN Response to OIR at 8-10.

other support structures provided in IRM2. The IRM2 in Southern California proposes to demonstrate the capabilities of flexible demand response resources, which are required by the CAISO, and test the capabilities of flexible demand response resources that IRM[53] attempted to accomplish. The Southern California pilot would replicate the IRM2 model for SCE and SD&E to enable third parties to learn how to bid demand response into the CAISO market.

We first address the Southern California pilot. In their program proposals, SCE and SDG&E request that the Commission not require them to participate in IRM2 for Southern California. Both contend that the IRM2 is redundant. SDG&E claims that it plans to bid a portion of its Capacity Bidding Program as a Proxy Demand Resource into the CAISO energy market beginning in 2014, thus making the IRM2 redundant and an inefficient use of ratepayer funds.[54] In its comments to the OIR, SCE indicates that four of its approved activities can meet similar objectives as the IRM2: Vehicle to Grid Pilot, which allows the Department of Defense to use its plug-in electric vehicle fleet to participate directly into the CAISO energy markets; Local Capacity Requirement Procurement, which will provide experience with soliciting preferred resources and their contribution to meet or reduce local capacity requirement needs; and the Preferred Resources Living Pilot, which will use demand response in a local area affected by the closure of Once-Through Cooling plants and the San Onofre Nuclear Generating Station (SONGS). Furthermore, SCE contends that if

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[53] IRM was piloted solely by PG&E.

[54] SDG&E Proposals at 30-31.

required to participate in IRM2 for Southern California, SCE may be unable to support these other activities simultaneously.[55]

We are encouraged by the statement made by SDG&E and SCE that they plan to bid more demand response into the CAISO energy markets in 2015. As we stated in our recent decision regarding bifurcation, we are concerned that little demand response has been integrated with the markets thus far.[56] We find that full implementation of bidding demand response into the markets is superior to the implementation of the proposed pilot project for two reasons. First, neither SDG&E nor SCE have the proposed budget amount to provide for a reasonable pilot. The proposal in the OIR defined a budget for SDG&E and SCE that was significantly less than the $2.48 million budgeted for PG&E's IRM2. SCE and Joint Demand Response Parties state that the amount proposed in the OIR would not be sufficient.[57] Second, it would not be reasonable for SDG&E and SCE to expend resources performing a pilot that is duplicative of work being performed in other pilots. Hence, we relieve SDG&E and SCE of the responsibility of performing the IRM2 Enhancement in Southern California.

However, we find that it is reasonable to track SDG&E and SCE's CAISO energy market integration efforts to ensure consistency and improvement, where needed. PG&E's efforts to integrate with the CAISO energy markets should also be tracked. Thus, we require PG&E, SDG&E and SCE to work with Commission Staff to develop the proper reporting methodology. Within 30 days of the

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[55] SCE Response to OIR at 4-5.

[56] D.14-03-026 at 24.

[57] *See*, for example, SCE Response to OIR at 6, Joint Demand Response Parties Response to OIR at 7.

issuance of this decision, PG&E, SDG&E and SCE shall meet with the appropriate Commission Staff to discuss and develop a reporting template and timeline to provide feedback on its experience with bidding into the CAISO energy markets. Within 30 days of that meeting, PG&E, SDG&E and SCE shall each file a finalized reporting template, including a timeline, via a Tier One Advice Letter for formal approval.

In comments to the proposed decision, PG&E and SDG&E requested that the development of this template be delayed until after the conclusion of the summer 2014 season, when there will be additional data available on bidding into the market to better inform the reporting requirements.[58] We disagree with this opinion. Data available over the summer months may be overlooked or unavailable after the season is concluded. Commission Staff will assist the utilities in determining what data should be collected.

We now address the Northern California pilot. PG&E requests the Commission to allow it to pursue a modified next step of the IRM2, a Supply Side Demand Response Pilot, instead of the staff proposed IRM2 Enhanced. PG&E states that its Supply Side Pilot will expand the service offerings to be bid into the CAISO energy market and the participating customer segments.[59] Furthermore, PG&E claims that its pilot will test products that may be able to provide a flexible ramping product to help with the integration of renewables. In comments to the OIR, PG&E contends that the staff proposed IRM2 Enhanced appears to simply amount to a capacity payment to an Energy Service Provider

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[58] PG&E Comments to Proposed Decision at 10 and SDG&E Comments to the Proposed Decision at 3.

[59] PG&E Proposal at Attachment B-1.

(ESP) for any wholesale demand response it can provide. PG&E asserts that "by not requiring the ESP to use PG&E's infrastructure, PG&E has no way to confirm whether the ESP is bidding in a manner consistent with the pilot requirements."[60]

In addition to PG&E, MCE and Olivine also filed proposals regarding the IRM2 for Northern California. In its proposal, MCE expresses interest in participating in the Northern California IRM2 but notes that "significant challenges remain" and suggests instead that a "pilot tailored to CCA customers would prove more fruitful than the IRM2 pilot encouraging non-Commission-regulated load serving entities participation in the CAISO energy markets."[61] MCE claims that demand response funding and cost recovery is anti-competitively biased, incentives are anti-competitive as currently implemented, and the timescale of the bridge funding does not facilitate CCA participation.[62] MCE surmises that it could provide a unique means for promoting demand response because it operates on a localized level.[63] Furthermore, MCE contends that a CCA-run pilot would create added benefit to ratepayers throughout the Commission's jurisdiction.[64]

Olivine, noting its operational experience with bidding demand response into the CAISO energy markets, presented an overview of lesser discussed challenges for integration into the CAISO energy markets.[65] Olivine supports

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[60] PG&E Response to OIR at 5.

[61] MCE Proposal at 2.

[62] *Id*. at 2-4.

[63] *Id*. at 4.

[64] *Id*. at 5.

[65] Olivine Proposal at Sections 1 and 2.

some form of IRM2 which provides for third party access to the wholesale market.[66] Claiming that current demand response programs are not well-aligned with the CAISO energy markets, Olivine suggests developing a methodology to capture demand response capabilities that are not captured otherwise. Olivine suggests several options for the IRM2 including the use of a statewide-approach, the use of a default demand response provider, or a separate mechanism that provides for an individualized approach.

Parties have provided thoughtful ideas on the Northern California IRM2 Enhancement pilot and the IRM2 pilot in general. We are encouraged that MCE is interested in participating in IRM2 and we are cognizant of the barriers they highlight. In response to MCE's comments, we remind MCE that the issue of cost recovery is not in the scope of this phase of the proceeding and the issue of additional time is a settled matter.

The Northern California IRM2 is a valid proposal as it fills the previously described gap in third-party experience and may provide the skills to enable third parties to stand alone as direct participants in the CAISO energy markets. However, the proposal is not perfect. Furthermore, the proposal has not gained much interest from other potential participants. We find that while PG&E's Supply Side pilot looks duplicative of IRM2, at first glance, the pilot's proposed new service offerings and expanded customer segments are valid for further exploration. Thus, we find it reasonable to cancel further exploration of the Northern California IRM2 enhancement and, instead, approve PG&E's

[66] Olivine at Section 3.

enhancements to its IRM2. Thus, we approve a budget of $2.45 million for PG&E to perform the Supply Side pilot.

3.4. Proposals for PG&E

PG&E requests the Commission to approve the continued operation of all 2012-2014 demand response programs during the 2015-2016 bridge years and to authorize the improvements to BIP, DBP, SmartAC, and AutoDR, as described below in Table 3. PG&E also specifically requests the Commission to approve the following: CBP program changes approved in Advice Letter 4332-E; revised AMP program agreements approved in D.14-02-033; and to carry over the PLS budget from 2012-2014, along with an additional $1.5 million in administration costs for the final PLS proposal.[67] PG&E also requests approval of three PG&E designed pilots instead of the pilots proposed by staff: 1) Supply Side Demand Response Pilot; 2) Excess Supply Pilot; and 3) Continuation of the current Transmission and Distribution Pilot.

In addition, two other parties proposed program improvements to PG&E's portfolio. The Joint Demand Response Parties recommend that the Commission authorize the continuation of the AMP program improvements as approved in D.14-02-033. ORA recommends modifying the marketing of PG&E's SmartRate program to target warmer climate zones.

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[67] The final PLS program was approved via disposition on September 5, 2013, of PG&E Advice Letter 4239-E.

These are listed below in Table 3.

TABLE 3

PARTY	DEMAND RESPONSE PROGRAM PROPOSALS FOR PG&E
Joint Demand Response (DR) Parties	Continue PG&E AMP[68] agreements approved in D.14-02-033 through 2015.
ORA	Modify PG&E's marketing of SmartRate[69] to target warmer climate zones.
PG&E	Revise BIP tariff language to: 1) clarify that the program can be dispatched by either PG&E or the CAISO; 2) clarify that the performance penalties are calculated on a 15-minute interval; and 3) standardize language to replace the word "penalty" with the words "excess energy charge."
PG&E	Revise Demand Bidding Program (DBP)[70] tariff language to: 1) clarify that the program can be dispatched by either the CAISO or PG&E based on pre-defined groups, 2) clarify the number of test events; 3) add the ability for PG&E to remove non-performing customers; 4) clarify that PG&E can dispatch an event at its discretion; 5) clarify dual enrollment order; 6) expand the bidding window opening; and 7) expand the dispatch window.

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[68] Aggregator Managed Portfolio programs provide opportunities for third party demand response providers or aggregators to enroll and manage retail customers in demand response programs.

[69] SmartRate is PG&E's program that provides enrollees lower overall rates during summer months but high rates for energy used during peak hours on SmartRate days.

[70] Demand Bidding Program is a program in which customers submit bids specifying the amount of energy usage they are willing to curtail during demand response events in exchange for a fixed incentive rate (SDG&E and PG&E) or bill credits (SCE).

TABLE 3

PARTY	DEMAND RESPONSE PROGRAM PROPOSALS FOR PG&E
PG&E	Revise SmartAC[71] tariff language to: 1) clarify that program can be dispatched during a Warning, Stage 1, 2, or 3; 2) clarify that the program can be dispatched on forecasted system conditions and CAISO procedures; and 3) clarify that the CAISO or PG&E can dispatch.
PG&E	Continue the revisions identified in the approved Advice Letter (Advice Letter) 4332-E through 2015-2016 for CBP.
PG&E	Continue the AMP agreement revisions approved by D.14-02-033.
PG&E	Revise the AutoDR[72] program by: 1) increasing education to vendors and customers; 2) streamlining application process; 3) increasing outreach efforts; and 4) providing technical assistance to current customers.
PG&E	Continue PLS program with only the remainder of the 2012-2014 budget and no requested budget for incentives.
PG&E	Evolve the IRM2[73] into a Supply Side Pilot consistent with the staff proposed IRM2 pilot.

[71] SmartAC is an AC Cycling program.

[72] Automatic Demand Response refers to automated technologies that allow a customer's equipment or facilities to reduce demand automatically in response to a demand response event or price signal, without the customer taking manual action.

[73] The IRM2 is an early stage training vehicle to give demand response providers experience in the CAISO energy markets. Structured to be a "one-stop shopping" operation where all services and infrastructure needed to bid demand response into the CAISO energy market are provided by the Program Administrator, some future participants may not need all these services.

TABLE 3

PARTY	DEMAND RESPONSE PROGRAM PROPOSALS FOR PG&E
PG&E	Develop an Excess Supply Pilot.
PG&E	Extend and continue the Transmission and Distribution Pilot into 2015-2016.

As further described below, we deny the requests by PG&E to revise its AC Cycling program and to carry over the 2012-2014 PLS budget,. We also deny the request by ORA to target the marketing of the SmartRate program. As we previously discussed, we approve PG&E's Supply Side Pilot.

We find all other requests to be reasonable and within the confines of prior budget requests. Furthermore, none of these requests are opposed by other parties. We discuss the denied proposals as well as other parties' views below.

PG&E is authorized a budget of $100,673,133 for its 2015-2016 Demand Response Programs as approved here and as listed in the ten Commission-approved categories in Attachment B of this decision.

Because we authorize the continuation of the AMP contracts as previously approved in D.14-02-033, we do not anticipate any changes in the contracts or the results of the cost-effectiveness analyses. No later than 45 days following the issuance of this decision, PG&E shall submit a tier 1 advice letter that includes copies of the AMP contracts for demand response program years 2015-2016.

As described in Table 3, PG&E requests approval of several changes to the DBP including: 1) specifically stating that PG&E can dispatch an event at its discretion ; and 2) expanding the dispatch window from the current 12 p.m. – 8 a.m. to 6 a.m. – 10 p.m.

PG&E explains that the ability to dispatch an event at its discretion is only a clarification. In comments to the proposed decision, PG&E explained that DBP is a voluntary program and customers are not penalized for participating in an event, no matter when or how many are called.[74] Furthermore, PG&E states that DBP is a statewide program and SCE is permitted to call a DBP event at its own discretion.[75] We conclude that the requested revision is reasonable as it provides the opportunity for increased participation. Therefore, we approve the request to allow PG&E to dispatch a DBP event at its own discretion.

Regarding the expansion of the dispatch window, PG&E contends that the requested expansion would increase the dispatch potential of a resource. As explained by several parties in comments to the proposed decision, DBP is a voluntary program and expanding the dispatch window, expands the opportunities to participate with no negative customer outcomes.[76] We conclude that the request to expand the DBP dispatch window is reasonable and we approve it with the requirement that PG&E amend its DBP tariff language to increase the minimum event window from two hours to four hours in order to comply with current Resource Adequacy standards.

PG&E recommends several changes to the SmartAC, its AC Cycling program, as described in Table 1. PG&E did not provide adequate explanation

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74 PG&E Comments to the Proposed Decision at 6-7.

75 *Ibid.*

76 See, for example, CLECA Comments to the Proposed Decision at 3-4, ORA Comments to the Proposed Decision at 11-12, PG&E Comments to the Proposed Decision at 6-7, and SCE Comments to the Proposed Decision at 6-7.

or justification for these changes. The requests are too vague to be reasonable. We deny all requested changes to PG&E's SmartAC program.

As described in Table 1, PG&E requests the Commission to approve education, outreach and application improvements to its AutoDR program. PG&E contends that these changes will improve a customer's experience with the program and increase performance. In comments to the proposals, ORA opposes the AutoDR revisions, as the changes "continue implementation of disjointed AutoDR programs. ORA explains that in compliance with D.12-04-045, PG&E, along with SDG&E and SCE, filed an Advice Letter with a proposal to develop a statewide Auto DR program with common program rules and incentive levels.[77] In response, ORA filed a protest stating that the Commission should delay changes to the program to the demand response bridge funding decision.[78] ORA claims that PG&E, SDG&E and SCE agreed that waiting was prudent. ORA highlights that none of the Utilities addressed the statewide AutoDR proposal in the filed proposals. ORA recommends that the Commission reject PG&E's AutoDR proposals as well as SCE and SDG&E's proposals to continue their status quo programs. Finally, ORA recommends that the Commission continue the Advice Letter process and require a supplemental filing from the three Utilities.

The Commission has previously determined that the three Utilities should create and implement a statewide AutoDR program. However, we agree with the Utilities that we should not implement a program that may require changes following the completion of our review in this proceeding. As we stated

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[77] ORA Response at 7.

[78] *Ibid*.

previously, the Guidance Ruling requires that changes be on a narrow basis. Thus, we find that the Utilities complied with the Guidance Ruling in regards to requesting or not requesting changes to the AutoDR program. We find PG&E's requested revisions to the AutoDR program to be reasonable and we approve them. Additionally, because these changes do not affect the budget or the cost-effectiveness results, we direct SDG&E and SCE to implement the same changes as discussed in the sections below focusing on each utility.

PG&E requests approval to continue its T&D Pilot. PG&E states that this pilot would move forward with the previously-approved Phase II efforts of the 2012-2014 demand response pilot. PG&E explains that implementation of the pilot was delayed due to a delay in the approval process.

In comments to the proposed decision, both PG&E and Clean Coalition provided additional supporting arguments for approval of this pilot. PG&E expressed the value to demand-side management, distribution system investments, and Transmission & Distribution investments.[79] In reply comments, Clean Coalition conveyed that this pilot is an example of integrated systems planning and deployment to coordinate developing initiatives and technologies to optimize investment and realize ratepayer savings.[80] Furthermore, Clean Coalition also noted that this type of integrated planning directly supports the

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[79] PG&E Comments to the Proposed Decision at 5.

[80] Clean Coalition Reply Comments to the Proposed Decision at 2.

recent Assembly Bill 327[81] requirements for the development of distribution system planning.[82]

We conclude that the request to authorize Phase II of the T&D Pilot is reasonable and we approve it. D.12-04-045 authorized funding for both Phase I and Phase II of this pilot, contingent upon approval of the pilot implementation plan in an advice letter filing. As we previously noted, the delay in the Advice Letter approval process did not allow PG&E to proceed with Phase II. The funding for Phase II is hereby shifted from the 2012-2014 Demand Response program budget to the 2015-2016 Bridge Funding Budget at an equivalent funding level.

Finally, ORA recommends that the Commission require PG&E to target SmartRate marketing dollars to customers in other areas where load reductions could provide greater impact and system benefits, but reduce marketing efforts to customers in cool coastal areas. ORA explains that, based on average load reduction, targeted marketing to increase participation in warmer local capacity areas would create greater load reduction than further marketing to increase participation in the Greater Bay Area and Northern Coast.[83] PG&E contends that it "does in fact conduct target marketing for SmartRate noting that the April 1, 2014 load impact evaluation will clearly indicate that PG&E's current marketing strategy has been effective.[84]

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[81] AB 327 requires PG&E to submit to the Commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources.

[82] *Ibid*.

[83] ORA Proposal at 19.

[84] PG&E Response at 6.

In comments to the proposed decision, ORA contends that the April 1, 2014 load impact evaluation does not include a breakdown of participation and load reduction based on regional climate differences, unlike the 2013 evaluation. To justify its arguments, ORA provides data indicating that SmartRate participation growth in cooler climates is higher than in hotter climates.[85] In reply comments to the proposed decision, PG&E disputes ORA's claims arguing that 1) the data demonstrates that a customer's climate zone is not the sole driver of customer responsiveness, 2) 2012 average load reductions for SmartRate™ only and dually enrolled customers were lower than in 2013, indicating successful targeting of new customers; and 3) ORA's mistakenly analyzes SmartRate customers rather than PG&E's marketing of SmartRate.[86]

We find the current targeted marketing of the PG&E SmartRate program to be sufficient. Because PG&E currently provides such targeted marketing, we find no further changes to the marketing of this program are necessary at this time.

3.5. Proposals for SDG&E

SDG&E requests the Commission to approve the continued operation of all 2012-2014 demand response programs during the 2015-2016 bridge years and to authorize the requested revisions to CBP, DBP, Local Marketing & Outreach, and the Small Customer Technology Deployment Program, as described above in Table 1. SDG&E also requests authorization to issue an RFP for new load control products and to reduce its budget in certain categories. Finally, SDG&E

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85 ORA Comments to the Proposed Decision at 6-9.

86 PG&E Reply Comments to the Proposed Decision at 3-4.

contends that the pilots proposed by staff are redundant and, instead, the Commission should allow SDG&E to continue its New Construction Demand Response pilot. See Table 4 below for a list of these proposals.

TABLE 4

PARTY	DEMAND RESPONSE PROGRAM PROPOSALs FOR SDG&E
SDG&E	Revise the CBP by: 1) adding a 30-minute option with a 15% increased incentive; 2) allowing participation of non-residential customers with less than 20kW; and 3) adjust the penalty structure.
SDG&E	Revise the DBP by: 1) increasing the day-of program payment by $100/MWh; and 2) increasing the Navy program payment by $100/MWh and decreasing the minimum load reduction from 3MW to 2MW.
SDG&E	Pursuant to D.12-04-045, recategorize marketing budget categories into local marketing education and outreach. Increasing marketing for CPP[87] due to it becoming a default program. Reducing overall marketing budget by 8%.
SDG&E	Expand Small Customer Technology Deployment [88] program to include small commercial customers. Investigate moving from no cost to customer cost-sharing approach.
SDG&E	Reduce budgets for Technical Incentives and Information Technology Infrastructure programs.

[87] Critical Peak Pricing imposes a short-term rate increase on customers during critical conditions.

[88] Small Customer Technology Deployment is a technology enabling program approved for SDG&E in D.12-04-045. D.12-04-045 limited participation to Peak Time Rebate residential customers only. The program was anticipated to drive market transformation.

TABLE 4

PARTY	**DEMAND RESPONSE PROGRAM PROPOSALs FOR SDG&E**
SDG&E	Issue additional Request for Proposal for Load Control Products.
SDG&E	Continue all other demand response activities as previously authorized and budgeted, including the New Construction Demand Response Pilot.

As further discussed below, we deny the following requests by SDG&E: to increase the incentives for the DBP program and the minimum load drop for the DBP Day-Of program, to issue a new RFP for load control products and to continue the New Construction Demand Response pilot. We also direct SDG&E to implement the changes we approved for PG&E's AutoDR program.

We grant all other requests by SDG&E and authorize a bridge funding budget of $39,121,940 for its 2015-2016 Demand Response Programs as approved in this Decision and as listed in the ten Commission-approved categories shown in Attachment 3.

SDG&E provides two DBPs: one is a Day-Of program and the other is a Day-Ahead program designed specifically for the Navy. SDG&E requests approval to increase the incentives and the minimum load drop for the DBP Day-Of program, as described in Table 4. SDG&E failed to provide sufficient data to support either change to its DBP Day-Of program. We, therefore, deny the proposed increased incentive payments and the increased minimum load drop for the DBP Day-Of program.

SDG&E requests to increase incentive payments for the DBP Navy program from $400/MWh to $500/MWh and to reduce the minimum load drop from 3 MW to 2 WM. Due to insufficient data to justify its approval, we conclude that increasing the incentives for the Navy program is not reasonable and we deny it. However, the data indicates that SDG&E's request to decrease the Navy program's minimum bid from 3MW to 2 MW is reasonable and we approve it.

In comments to the proposed decision, SDG&E argues that the Day-Ahead DBP administered by other utilities in California provide higher customer incentives and, therefore, SDG&E should be allowed to increase its incentives for the Navy program.[89] We disagree with SDG&E's argument based on the clear differences in the programs provided by other utilities. SDG&E's Navy program can only be triggered during a CAISO Stage 1 or 2 alert, or during a local emergency. The DBP provided by PG&E and SCE can be triggered for a variety of reasons, e.g. temperature, energy prices, utility procurement needs as well as CAISO alerts. These differences make is reasonable to provide higher incentives for the PG&E and SCE DBP.

SDG&E requests approval to issue a new RFP for load control products as opportunities arise. We find this request to be duplicative of a prior request approved in D.13-04-017. SDG&E provides no discussion of this approved request nor did it offer an update regarding the outcome of the RFP. We conclude approval of this request is not reasonable and we deny the request to issue a new RFP for load control products.

SDG&E requests approval to continue the New Construction Demand Response Pilot. SDG&E states that the current pilot was not approved until February 2013 and is authorized to end on December 31, 2014. SDG&E explains

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[89] SDG&E Comments to the Proposed Decision at 6.

that most new construction projects can take from 18 months to three years for completion.[90] SDG&E contends that the long-term nature of most projects, along with the limited time frame for the initial pilot, has made it difficult to find projects that fit the current pilot model.[91] Given the late start of the pilot, we will allow it to extend into the 2015-2016 program cycle but with its current budget. Funding for the continuation of the New Construction Demand Response pilot, in the amount of $750,667[92] shall be shifted from the 2012-2014 budget to the 2016-2016 bridge funding budget.

As previously discussed, we approve the requested changes in PG&E's AutoDR program and require SDG&E to implement the same changes. By January 15, 2015, SDG&E shall file a Tier One Advice Letter explaining how and when the AutoDR program changes were implemented.

3.6. Proposals for SCE

SCE requests that the Commission allow SCE to continue its demand response programs and activities as approved in D.12-04-045 and modified in D.13-01-024 (AMP agreements), D.13-04-017 and D.13-07-003 (SONGS-related modifications.)[93] SCE contends that it has improved the effectiveness of demand response programs as a result of modifications approved by the Commission in D.11-11-002,[94] D.12-04-045, D.13-04-017 and D.13-07-003, and therefore does not

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[90] SDG&E Proposal at 13-14.

[91] *Ibid*.

[92] This amount is equal to 2/3 of the budget approved in D.12-04-045.

[93] SCE Proposal at 3-4.

[94] D.11-11-002 authorized modifications to the Summer Discount Plan, which provides bill reductions to residential electricity users who permit SCE to curtail power to air conditioners.

propose any further program changes at this time.[95] Furthermore, SCE states that it expects to bid demand response resources into the CAISO energy markets beginning in Summer 2014.[96] SCE requests that the Commission specifically authorize: 1) extensions of existing AMP agreements for 2015 and 2016; 2) continuation of ongoing research activities; and 3) completion of 2012-2014 committed pilots that experienced delays and may not be completed by the end of 2014. SCE does not propose any new pilots. Both the Joint Demand Response Parties and ORA also recommend revisions to the AMP program agreements.

Table 5 below lists the program improvements recommended for SCE.

TABLE 5

PARTY	DEMAND RESPONSE PROGRAM PROPOSALS FOR SCE
Joint DR Parties	Require SCE to continue to negotiate for improved AMP agreements for 2015-2016.
ORA	Require SCE to revise AMP agreements to include the following changes: cease practice of seller-directed tests, provide payments based on performing of all hours of events; and modify from day-of notification to 30 minutes.
SCE	Extend all current funding, programs and program modifications authorized through D.11-11-002, D.12-04-045, D.13-04-017, and D.13-07-003.
SCE	Extend current AMP agreements through 2016.

[95] SCE Proposal at 3.

[96] *Ibid*.

TABLE 5

PARTY	DEMAND RESPONSE PROGRAM PROPOSALS FOR SCE
SCE	Extend existing pilots that have not reached completion and authorize that the previously-approved budget amount be extended beyond 2014.
SCE	Continue ongoing research activities.

ORA and the Joint Demand Response Parties recommend that the Commission should authorize extensions of the AMP agreements but the two disagree on the specifics. ORA specifies several requirements that the Commission should require in the extension,[97] while the Joint Demand Response Parties contend that the Commission should require SCE to continue to negotiate with the AMP agreement parties. The Joint Demand Response Parties request that a Ruling be issued setting a deadline of July 1, 2014 for notifying the Commission that negotiations are concluded. In reply, SCE states that it is willing to continue negotiations and will consider ORA's recommendations during agreement discussions. However, SCE requests that the Commission not require any specifications in the agreements since the agreements will be negotiated outside the Commission process but with final approval by the Commission.

We approve SCE's 2015-2016 demand response budget request to continue demand response programs as approved by D.12-04-045 and modified by D.13-01-024, D.13-04-017, and D.13-07-003, and include the requested ongoing

[97] Those requirements included specifications on test date, base capacity payments, and notification times.

research activities and the continuation of pilots approved and budgeted in 2012-2014 but not yet completed. We agree that SCE has implemented many changes over the past two years to improve the demand response programs. Because there are no other changes in its portfolio, we expect SCE to focus efforts on direct participation in the CAISO energy markets and to report to the Commission on program performance. SCE should work with Commission staff to determine proper routine reporting requirements for its CAISO efforts. We clarify that, because SCE is not required to perform any new pilots, its budget in the pilot category for 2015-2016 is $0.

The Commission previously approved modifications to PG&E's AMP agreements noting that the changes advance the agreements and associated demand response programs toward increased demand response and improved alignment with the CAISO energy markets, which complement the goals of the R.13-09-011.[98] Furthermore, SCE stated its intention to continue negotiations with its AMP contractors. We, therefore, find it reasonable to require SCE to continue to negotiate with its AMP program contractors for modified and improved 2015-2016 agreements.

We recognize that the AMP agreements are negotiated outside the Commission process. Thus, we do not require any specifications in the agreements. However, we encourage SCE and its AMP program contractors to consider the changes approved by the Commission in the PG&E AMP agreement improvements[99] and the changes recommended by ORA.[100] We also encourage

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[98] D.13-02-033 at 4.

[99] See D.14-02-033, Approving Joint Petition For Modification of D.13-01-024, regarding AMP program agreements.

SCE and its contractors to work collaboratively with each other and with ORA in the process of revising the agreements, to aid in the Commission approval process. No later than July 15, 2014, SCE shall file application Tier Two Advice Letter requesting approval of 2015-2016 re-negotiated AMP program agreements. We note that because these are renegotiated extended contracts and because we authorize the budget amount in this decision, we do not require a separate application. We are requiring the use of the same procedural process as that directed in D.12-04-045.[101]

SCE is granted a bridge budget of $172,307,062 for its 2015-2016 Demand Response Programs as approved in this decision and as listed in the ten Commission-approved categories in Attachment 4.

4. 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 on May 5, 2014, by CLECA, DACC/AReM. the Joint Demand Response Parties, Olivine, ORA, PG&E, SDG&E, SCE, and TURN; and reply comments were filed on May 12, 2014 by Clean Coalition, Consumer Federation of California, the Joint Demand Response Parties, Olivine, ORA, PG&E, SDG&E, SCE and TURN. In response to comments to the proposed decision, corrections and clarifications have been made throughout this decision.

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[100] ORA Proposal.

[101] See D.12-04-045 at 76 regarding PG&E's renegotiated AMP agreements.

5. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Kelly A. Hymes is the assigned ALJ in this proceeding.

Findings of Fact

1. In D.14-01-004, the Commission found it practical to revise demand response programs to improve their success, but on a narrow basis so that revisions can be implemented by 2015.
2. The requirements in the Guidance Ruling define the boundaries of recommended demand response program revisions so that the Commission's review of the proposals would be efficient.
3. Proposals to revise demand response programs must meet the requirements of the Guidance Ruling.
4. Changes to the cost allocation and cost recovery methodology are not in the scope of this phase of the proceeding.
5. Bridge funding allows programs and activities to continue, as is, so that the Commission can focus on the other issues in this proceeding.
6. Cost allocation and cost recovery issues will be addressed in Phase Two of this proceeding.
7. The Guidance Ruling directed that program improvements should be on a narrow basis so as to enable implementation by 2015.
8. D.14-01-004 cautioned parties that disputed facts may not allow recommended revisions to meet the requirements of speedy implementation.
9. The Scoping Memo only envisioned one or two years of bridge funding.
10. Bridge funding is limited to the years 2015 and 2016.
11. Funding for 2015-2016 bridge years is capped at 2013-2014 levels.

12. CESA failed to provide analyses, studies or reports to support its proposal to revise the PLS program.

13. The Commission, through SCE Advice Letter 2913-E, adopted a program modification process for recommending changes to the PLS program.

14. EnergyHub's proposals to extend the CBP to residential customers, to allow AC Cycling customers to use their own devices, and to focus pilots on residential customers using load management technologies lack supporting rationale based on analyses, studies or reports.

15. RENs provide no supporting rationale based on analyses, studies or reports for its proposal to implement a public agency technical support program.

16. Pursuant to the terms of the Reliability Based Demand Response Settlement, BIP can only be used after the CAISO has used all other resources in its balancing authority.

17. Changes in the CAISO Operating Procedure made without the consent of all parties to the Settlement could harm the Settlement.

18. The Commission addressed dynamic rates and marketing of such rates throughout D.12-04-045.

19. ORA's proposal regarding TOU marketing lacks specificity.

20. Commission rules already provide for the aspects of ORA's proposals that would prohibit misleading marketing.

21. The Commission has an open proceeding on dynamic rates where ensuring accurate marketing may be addressed in more depth.

22. ORA's proposal regarding TOU marketing is unnecessary.

23. The additional reporting requested by ORA will provide transparency.

24. The concerns by the Utilities regarding confidentiality and duplication are valid.

25. The Base Interruptible Program and the Agricultural Pumping Interruptible Program are emergency-responsive programs, not price-responsive.

26. The customer responsiveness pilot (behavior pilot) is duplicative of other past and current similar efforts.

27. The behavior-based pilot is an inefficient use of ratepayer funds given the similar past and current efforts.

28. We are encouraged by the plans of SDG&E and SCE to bid more demand response into the CAISO energy markets in 2015.

29. The Commission has expressed concern that little demand response has been integrated with the CAISO energy markets thus far.

30. Neither SDG&E nor SCE have an adequate budget amount to provide for a reasonable pilot, as that proposed by staff.

31. The IRM2 for Southern California is duplicative of activities already being performed by SDG&E and SCE.

32. Full implementation of bidding demand response into the markets is superior to the implementation of the proposed pilot project.

33. The issue of cost recovery is not in the scope of this phase of the proceeding.

34. The issue of additional time is a settled matter.

35. The Northern California IRM2 is a valid proposal as it fills the previously described gap in third party experience and may provide the skills to enable third parties to stand alone as direct participants in the CAISO energy markets.

36. The Northern California IRM2 Enhancement pilot proposal has not garnered much interest.

37. PG&E's Supply Side pilot proposed new service offerings and expanded customer segments are valid for further exploration.

38. PG&E's AMP contracts were previously approved in D.14-02-033.

39. DBP is a voluntary program and customers are not penalized for participating in an event.

40. The requested changes to PG&E's DBP improves the opportunity for increased customer participation.

41. PG&E did not provide adequate explanation or justification for its requested changes to its SmartAC program.

42. The Commission has previously determined that the three Utilities should create and implement a statewide AutoDR program.

43. The Commission should not implement a program now that may require changes following the completion of our review in this proceeding.

44. The Utilities complied with the Guidance Ruling in regards to requesting or not requesting changes to the AutoDR program.

45. The changes to the AutoDR program do not impact the budget or the cost-effectiveness results.

46. Implementation of PG&E's T&D pilot was delayed due to a delay in the approval process.

47. The T&D pilot provides value demand-side management, distribution system investments, and T&D investments.

48. The T&D pilot is an example of integrated systems planning and deployment that coordinates developing initiatives and technologies to optimize investment and realize ratepayer savings.

49. The T&D pilot supports AB 327 requirements.

50. All other requests by PG&E in its proposal not otherwise discussed are reasonable and within the confines of prior program approvals.

51. SDG&E failed to provide sufficient data to support either the proposed increase in incentive payments for its DBP Day-Of and Navy program or the increase in the minimum load drop from 50% to 60% for the Day-Of program.

52. SDG&E's DBP can only be triggered during CAISO Stage 1 and 2 emergencies and local emergencies.

53. PG&E and SCE's DBP can be triggered for a variety of reasons.

54. SDG&E's requests to issue a new RFP for load control products as opportunities arise is duplicative of a prior request approved in D.13-04-017.

55. SDG&E did not provide any discussion of the prior approved request for a RFP for load control products nor did it offer an update regarding the outcome of the RFP.

56. SDG&E's current New Construction Demand Response Pilot was not approved until February 2013 and is only authorized through December 31, 2014.

57. The Commission approved modifications to PG&E's AMP agreements noting that the changes advance the agreements and associated demand response programs toward increased demand response and improved alignment with the CAISO energy markets, which complement the goals of the R.13-09-011.

58. The AMP agreements are negotiated outside the Commission process.

59. SCE's AMP agreements will be renegotiated and extended agreements.

60. SCE has implemented many changes over the past two years to improve the demand response programs.

61. SCE stated its intention to bid demand response resources into the CAISO market beginning in Summer 2014.

62. SCE is not required to perform any new pilots.

Conclusions of Law

1. It is reasonable that cost recovery changes will not be made in this decision or in this phase of the proceeding.

2. It is reasonable to deny the request to take additional time for Phase One of the proceeding.

3. It is reasonable to deny the request by CESA to approve changes to the PLS programs during the 2015-2016 demand response bridge fund.

4. It is reasonable to deny the requests by EnergyHub to revise the CBP, AC Cycling program and pilots for the 2015-2016 demand response program cycle.

5. It is reasonable to deny the proposal by RENs to approve a public agency technical support program for the 2015-2016 demand response bridge funding.

6. It is reasonable to deny ORA's request to change the BIP dispatch order because of the potential impact to the Settlement.

7. It is reasonable to deny ORA's proposal to ensure accurate marketing for the TOU rates.

8. The additional reporting requirements should include parameters to avoid duplication and ensure confidentiality of protected data.

9. The request by ORA for additional reporting is reasonable.

10. It is reasonable to deny approval of the staff proposed behavior based pilot.

11. It is not reasonable for SDG&E and SCE to expend resources performing a pilot that is duplicative of work being performed in other pilots.

12. It is reasonable that we relieve SDG&E and SCE of the responsibility of performing the IRM2 Enhancement in Southern California.

13. It is reasonable to track PG&E, SDG&E and SCE's CAISO integration efforts to ensure consistency and improvement.

14. It is reasonable to approve PG&E's Supply Side pilot.

15. It is reasonable for PG&E to be allowed to call a DBP event at its own discretion.

16. It is reasonable to approve the PG&E request to expand the DBP dispatch window.

17. It is reasonable to deny all PG&E requests to revise its SmartAC program.

18. It is reasonable to approve PG&E's requested revisions to the AutoDR program.

19. It is reasonable to require SDG&E and SCE to implement the same revisions to its AutoDR program as those approved for PG&E.

20. It is reasonable to approve the request by PG&E to continue the T&D Pilot for two additional years.

21. It is reasonable to deny the requests of SDG&E to increase the incentives for the DBP Day-Of and Day-After and to decrease the minimum load drop for the DBP Day-Of.

22. It is reasonable to deny the request of SDG&E to issue a new RFP for load control products.

23. It is reasonable to approve the request by SDG&E for 2015-2016 funding for continuation of the New Construction Demand Response Pilot.

24. It is reasonable to approve all other requests by SDG&E.

25. It is reasonable to require SCE to continue to negotiate with its AMP program contractors for contract extensions through 2016.

26. It is reasonable to require SCE to provide new reporting on its efforts to bid demand response into the CAISO energy markets.

27. It is reasonable to approve SCE's all other requests.

O R D E R

IT IS ORDERED that:

1. We adopt the request presented by the Office of Ratepayer Advocates (ORA) to require Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company to provide weekly exception reporting to the Commission Energy Division and ORA to identify and describe each occurrence when a demand response program was economic to dispatch but the utility decided to utilize a non-demand response resource instead.

2. Within 30 days from the issuance of this decision Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company (jointly, the Utilities) shall organize and meet with the appropriate Commission Staff, the Office of Ratepayer Advocates, and any other interested stakeholders to develop an agreed-upon reporting template for providing weekly exception reporting, using the draft reporting template in Attachment A as a starting point. All stakeholders should take into consideration other utility reporting requirements to ensure no unnecessary duplication. The required reporting shall include parameters to ensure the confidentiality of protected data. Within 30 days following the initial meeting, the Utilities shall file a Tier Two Advice Letter requesting approval by the Commission of the final reporting template.

3. No later than December 31, 2014, Commission Staff shall host a workshop to discuss lessons learned from the weekly exception reporting. Staff shall notice this workshop to the service list in Rulemaking 13-09-011.

4. Within 30 days of the issuance of this decision, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE) shall meet with the appropriate Commission Staff to discuss and develop a reporting template and timeline to provide feedback on the utilities' experience with bidding into the California Independent System Operators (CAISO) energy markets during the 2015-2016 demand response program cycle. Within 30 days of this initial meeting, PG&E, SDG&E and SCE shall each file a finalized reporting template and timeline for approval via a Tier One Advice Letter.

5. We authorize a budget of $2.45 million for Pacific Gas and Electric Company to conduct the Supply Side pilot.

6. We approve the following requests by Pacific Gas and Electric Company for its 2014-2015 Demand Response Programs and Activities:

a. the continued operation of all 2012-2014 demand response programs during the 2015-2016 bridge years, except as otherwise denied in this decision;

b. the improvements to its Base Interruptible Program, the Demand Bidding Program, and the Auto Demand Response program;

c. the revisions to the Capacity Bidding Program approved in Advice Letter 4332-E;

d. the revisions to the Aggregated Managed Portfolio program agreements approved in D.14-02-033;

e. the completion of Phase II of the Transmission & Distribution Pilot; and

f. the implementation of its proposed Supply Side and Excess Supply Pilots.

7. The following requested changes to Pacific Gas and Electric Company (PG&E) 2015-2016 Demand Response Programs are denied:

a. all changes to the Air Conditioning Cycling program;

b. the request to carry over the unspent and uncommitted portion of the 2012-2014 Permanent Load Shifting budget; and

c. the request by the Office of Ratepayer Advocates to target the marketing of the SmartRate program.

8. Pacific Gas and Electric Company, within 45 days of the issuance of this decision, shall file a Tier 1 Advice Letter, along with copies of the Aggregator Managed Portfolio Program Agreements for approval by the Commission.

9. Pacific Gas and Electric Company, within 45 days of the issuance of this decision, shall file a Tier 1 Advice Letter to make the necessary tariff changes to its demand response programs as approved in this decision.

10. We authorize a budget of $100,673,133 for Pacific Gas and Electric Company for its 2015-2016 demand response programs to be allocated in the previously approved demand response categories as indicated in Attachment 2.

11. By January 15, 2015, San Diego Gas & Electric Company shall file a Tier One Advice Letter explaining how and when it implemented the following required changes to its Automatic Demand Response program:

a. increase program education to vendors and customers to foster understanding of program benefits;

b. streamline program application process to facilitate applying for program incentives;

c. increase outreach efforts focused on lighting projects; and

d. provide technical assistance to existing program customers.

12. We approve the following requests by San Diego Gas & Electric Company for its 2014-2015 Demand Response Programs and Activities:

a. the continued operation of all 2012-2014 demand response programs during the 2015-2016 bridge years, except as otherwise denied in this decision;

b. the required revisions to the Automated Demand Response program;

c. to continue the New Construction Demand Response pilot and

d. the improvements to its Capacity Bidding Program, the Demand Bidding Program, Local Marketing & Outreach and the Small Customer Technology Deployment Program, except as otherwise denied in this decision.

13. The following requested changes to the San Diego Gas & Electric Company 2015-2016 Demand Response Programs are denied:

a. to increase the incentives for the Demand Bidding Program;

b. to increase the minimum load drop for the DBP Day-Of program; and

c. to issue a new Request for Proposals for load control products.

14. San Diego Gas & Electric Company, within 45 days of the issuance of this decision, shall file a Tier 1 Advice Letter to make the necessary tariff changes to its demand response programs as approved in this decision.

15. We authorize a budget of $39,872,607 for San Diego Gas & Electric Company for its 2015-2016 demand response programs to be allocated in the previously approved demand response categories as indicated in Attachment 3:

16. We approve the following requests by Southern California Edison Company for its 2014-2015 Demand Response Programs and Activities:

a. the continued operation of all 2012-2014 demand response programs and program modifications, during the 2015-2016 bridge years, except as otherwise denied in this decision;

b. the required revisions to the Automatic Demand Response Program, and

c. the continuation of ongoing research activities.

17. We authorize a budget of $172,307,062 for Southern California Edison Company for its 2015-2016 demand response programs to be allocated in the previously approved demand response categories as indicated in Attachment 4.

18. Southern California Edison Company (SCE) shall continue to negotiate in good faith with its Aggregator Managed Portfolio (AMP) program contractors to extend the agreements through 2016. SCE and its AMP program contractors are encouraged to consider the changes approved by the Commission in the Pacific Gas and Electric Company AMP agreement improvements approved in Decision 14-02-033 as well as the changes recommended by the Office of Ratepayer Advocates (ORA). SCE and its contractors are encouraged to work collaboratively with each other and with ORA in the process of revising the agreements, to aid in the Commission approval process.

19. No later than July 15, 2014, Southern California Edison Company (SCE) shall file a Tier Two Advice Letter for approval of 2015-2016 re-negotiated Aggregator Managed Portfolio program agreements.

20. The request by the Direct Access Customer Coalition/Alliance for Retail Energy Markets that the Commission consider any cost allocation and cost recovery determinations made in Phase Two of this proceeding applicable to the bridge years of 2015 and 2016 is denied.

21. The request by the Office of Ratepayer Advocates and Southern California Edison Company to take additional time to develop, review and determine demand response program improvements for 2015 and 2016 is denied.

22. Phase One of Rulemaking 13-09-011 is closed. Phases Two through Four of Rulemaking 13-09-011 remain open to address outstanding issues.

This order is effective today.

Dated May 15, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

ATTACHMENT 1

REPORTING TEMPLATE FOR TRANSPARENCY OF THE UTILITIES' ADMINISTRATION OF DEMAND RESPONSE

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Date Trigger Is Met	Time Trigger Is Met	Program or Contract Name(1)	Lead Time for Notification	Date & time when program is eligible to be implemented	Specify the Type of Trigger Conditions Met (2)	Was Resource Dispatched when available - see column 5 (Y/N)?	If No, Explain the reason why not (3)	Forecasted availability of the program or contract, MW	Actual MW dispatched of the program of contract	Duration of dispatch	Tariff-based constraints restricting availability (4)	Strategy-based constraints preventing dispatch (5)	Highest Price that a non-Demand Response resource that is part of the utilities' portfolio was *forecast* to be Dispatched	Highest Price that a non-Demand Response resource that is part of the utilities' portfolio was *actually* Dispatched	Was the resource noted in column 15 self scheduled?	Please note all non-DR resources that are part of the utilities' portfolio that are forecast to have marginal commitment costs that are above the energy value of the DR program resource at the time they are available (i.e. column 5)

(1) If the same trigger applies to multiple programs or contracts, each program or contract should be reported on a separate row
(2) Specify the exact market price trigger, heat rate trigger, temperature trigger, system load trigger and/or other trigger and how it was met. For example, "the trigger is a temperature above 95 degrees F, and we hit 98 degrees F" or an explanation with similar detail.
(3) Provide enough explanation that shows the reasoning for not dispatching the program.
(4) Provide explanation on any tariff-based constraints preventing dispatch. For example, does the resource have a limited number of dispatches per unit of time (season, month, other)? If so, how many dispatches have already occurred, and how many remain to be called?
(5) Provide explanation on any internal strategy based constraints preventing dispatch. For example, a preference not to call on weekends or day-of, or preference to only dispatch 1/3 of the resource at a time, or preference for shorter duration.
(6) Input the most relevant forecast and actual price based on lead time for notification and specify what the "most relevant price" for comparison is. This may be the same as the day-ahead information for a day-ahead program or it could be hours ahead information for day-of programs.

(END OF ATTACHMENT 1)

ATTACHMENT 2

BUDGET FOR PACIFIC GAS AND ELECTRIC COMPANY

PROGRAM	D.12-04-045 AUTHORIZED	ESTIMATED 2013-2014	REQUESTED 2015-2016	AUTHORIZED 2015-2016
BIP	$666,349	$444,233	$444,455	$444,233
OBMC/SLR	$413,532	$275,688	$275,826	$275,688
CAT 1 Total	$1,079,881	$719,921	$720,281	$719,921
DBP	$3,216,000	$2,144,000	$1,067,200	$1,067,200
CBP	$11,563,485	$7,708,990	$4,737,930	$4,737,930
PeakChoice	$1,750,000	$1,166,667	$0	$0
AC Cycling	$19,353,335	$12,902,223	$12,908,674	$12,908,674
CAT 2 Total	$35,882,820	$23,921,880	$18,713,805	$18,713,804
AMP	$1,187,700	$791,800	$792,196	$791,800
CAT 3 Total	$1,187,700	$791,800	$792,196	$791,800
Auto DR	$26,297,459	$17,531,639	$17,540,405	$17,531,639
DR Em Tech	$3,749,238	$2,499,492	$2,500,742	$2,499,492
CAT 4 Total	$30,046,697	$20,031,131	$20,041,147	$20,031,131
Supply Side Pilot	$2,458,336	$1,638,891	$2,458,336	$2,458,336
T&D DR	$2,458,336	$1,638,891	$1,622,500	$1,622,500
Plug in hybrid	$3,000,000	$2,000,000	$0	$0
Excess Supply	$0	$0	$1,100,000	$1,100,000
CAT 5 Total	$7,916,672	$5,277,781	$5,180,836	$5,180,836
DRMEC	$14,520,981	$9,680,654	$8,372,159	$8,372,159
DR Research	$1,200,000	$800,000	$0	$0
CAT 6 Total	$15,720,981	$10,480,654	$8,372,159	$8,372,159

BUDGET FOR PACIFIC GAS AND ELECTRIC COMPANY (CONTINUED)				
PROGRAM	**D.12-04-045 AUTHORIZED**	**ESTIMATED 2013-2014**	**REQUESTED 2015-2016**	**AUTHORIZED 2015-2016**
Statewide Mkt	$3,500,000	$2,333,333	$0	0
Core Mkt	$13,000,000	$8,666,667	$8,671,000	$8,671,000
Educ / Trng	$771,993	$514,662	$514,919	$514,919
CAT 7 Total	$17,271,993	$11,514,662	$9,185,919	$9,185,919
Forecasting	$14,407,887	$9,605,258	$9,610,061	$9,605,258
Enrollment	$15,787,400	$10,524,933	$10,530,196	$10,524,933
Notifications	$7,427,715	$4,951,810	$4,954,286	$4,951,810
Integration	$3,893,342	$2,595,561	$2,596,859	$2,595,561
CAT 8 Total	$41,516,344	$27,677,563	$27,691,401	$27,677,563
IDSM	$6,243,500	$4,162,333	$0	$0
CAT 9 Total	$6,243,500	$4,162,333	$0	$0
DR HAN	$20,020,000	$13,346,667	$0	$0
PLS	$15,000,000	$10,000,000	$1,500,000	$10,000,000
CAT 10 Total	$35,020,000	$23,346,667	$1,500,000	$10,000,000
TOTAL BUDGETS	$191,886,588	$127,924,392	$92,197,744	$100,673,133

Estimated 2013-2014 -- equal to 2/3 of D.12-04-045 plus any additional increases from D.13-01-024 and D.13-04-017.

(END OF ATTACHMENT 2)

ATTACHMENT 3

BUDGET FOR SAN DIEGO GAS & ELECTRIC COMPANY							
PROGRAM	D.12-04-045 AUTHORIZED		ESTIMATED 2013-2014		REQUESTED 2015-2016		AUTHORIZED 2015-2016
BIP	$4,014,000		$2,676,000		$2,956,077		$2,676,000
CAT 1 Total	$4,014,000		$2,676,000		$2,956,077		$2,676,000
DBP	$0		$1,755,808		$1,755,810		$1,755,808
CBP	$11,789,000		$7,859,333		$8,191,338		$7,859,333
PeakTime Rebate	$485,000		$323,333		$323,290		$323,333
CAT 2 Total	$12,274,000		$9,938,474		$10,270,438		$9,938,475
CAT 3 Total	$0		$0		$0		$0
ET	$2,111,000		$1,407,333		$1,410,970		$1,407,333
SCTD	$9,464,167		$6,309,445		$8,189,652		$6,309,445
TI	$8,973,000		$5,982,000		$5,571,418		$5,982,000
CAT 4 Total	$20,548,167		$13,698,778		$15,172,040		$13,698,778
Locational DR	$433,000		$0		$0		$0
New Construction	$1,126,000		$0		$974,236		$750,667
CAT 5 Total	$1,559,000		$1,039,333		$974,236		$0
EMV	$5,115,000		$3,410,000		$3,439,462		$3,410,000
DR Research	$600,000		$400,000		$400,000		$400,000
CAT 6 Total	$5,715,000		$3,810,000		$3,839,462		$3,810,000
CEAO	$1,100,000		$733,333		$0		0
OLM	$4,650,000		$3,100,000		$0		0
LMEO	$0		$0		$3,698,170		$3,698,170
CAT 7 Total	$5,750,000		$3,833,333		$3,698,170		$3,698,170

BUDGET FOR SAN DIEGO GAS & ELECTRIC COMPANY (CONTINUED)						
PROGRAM	**D.12-04-045 AUTHORIZED**		**ESTIMATED 2013-2014**		**REQUESTED 2015-2016**		**AUTHORIZED 2015-2016**
Regulatory Policy	$2,231,000		$1,487,333		$1,531,077		$1,531,077
IT	$5,410,000		$3,606,667		$1,769,440		$1,769,440
CAT 8 Total	$7,641,000		$5,094,000		$3,300,517		$3,300,517
IDSM	$984,359		$0		$0		0
CAT 9 Total	$984,359		$0		$0		$0
PLS	$3,000,000		$2,000,000		$2,000,000		$2,000,000
CAT 10 Total	$3,000,000		$2,000,000		$2,000,000		$2,000,000
TOTAL BUDGET	$61,485,526		$40,990,351		$42,210,940		$39,872,607

Estimated 2013-2014 -- equal to 2/3 of D.12-04-045 plus any additional increases from D.13-01-024 and D.13-04-017. Specifically, the DBP budget was approved in D1304017 for 2013-2014 budgets only.

(END OF ATTACHMENT 3

ATTACHMENT 4

BUDGET FOR SOUTHERN CALIFORNIA EDISON COMPANY				
PROGRAM	**D.12-04-045 AUTHORIZED**	**ESTIMATED 2013-2014**	**REQUESTED 2015-2016**	**AUTHORIZED 2015-2016**
Ag Pumping	$1,543,052	$1,028,701	$1,028,701	$1,028,701
BIP	$2,407,226	$1,604,817	$1,604,817	$1,604,817
OBMC/	$37,475	$24,983	$24,983	$24,983
Rotating Outages	$321,658	$214,439	$214,439	$214,439
SLR	$15,000	$10,000	$10,000	$10,000
CAT 1 Total	$4,324,411	$2,882,941	$2,882,941	$2,882,941
Ancillary Svcs	$0	$0	$0	$0
CBP	$661,287	$440,858	$440,858	$440,858
DBP	$1,483,686	$989,124	$989,124	$989,124
AC Cycling	$64,391,768	$42,927,845	$42,927,845	$42,927,845
PeakTime Reb	$4,707,515	$3,138,343	$3,138,343	$3,138,343
CAT 2 Total	$71,244,256	$47,496,171	$47,496,171	$47,496,171
AMP	$0	$49,300,000	$49,300,000	$49,300,000
CAT 3 Total	$0	$49,300,000	$49,300,000	$49,300,000
Auto DR	$35,576,277	$28,717,518	$28,717,518	$28,717,518
DR Em Tech	$7,303,969	$5,844,313	$5,844,313	$5,844,313
CAT 4 Total	$42,880,246	$34,561,831	$34,561,831	$34,561,831
Smart Charging	$600,000	$400,000	$0	$0
Workplace Ch	$1,243,125	$828,750	$0	$0

BUNDGET FOR SOUTHERN CALIFORNIA EDISON COMPANY (CONTINUED)							
PROGRAM	**D.12-04-045 AUTHORIZED**		**ESTIMATED 2013-2014**		**REQUESTED 2015-2016**		**AUTHORIZED 2015-2016**
DRMEC	$6,404,147		$4,269,431		$4,269,431		$4,269,431
DR Research	$1,200,000		$800,000		$800,000		$800,000
CAT 6 Total	$7,604,147		$5,069,431		$5,069,431		$5,069,431
Statewide Mkt	$5,500,000		$3,841,667		$3,841,667		$3,841,667
Local Mkting	$22,000,000		$16,566,667		$11,730,000		$11,730,000
CAT 7 Total	$27,500,000		$20,408,334		$11,730,000		$11,730,000
DR Systems	$17,900,032		$11,933,355		$11,933,355		$11,933,355
DR Forecasting	$0		$0		$0		$0
CAT 8 Total	$17,900,032		$11,933,355		$11,933,355		$11,933,355
IDSM	$0		$0		$0		$0
CAT 9 Total	$0		$0		$0		$0
PLS	$14,000,000		$9,333,333		$9,333,333		$9,333,333
CAT 10 Total	$14,000,000		$9,333,333		$9,333,333		$9,333,333
TOTAL BUDGET	**$187,296,217**		**$185,608,478**		**$172,307,062**		**$172,307,062**

Estimated 2013-2014 is equal to 2/3 of D.12-04-045 plus any additional increases from D.13-01-024 and D.13-04-017.

SCE did not provide a breakdown of their budget request. SCE only stated that they request the same budget amounts as approved in D.12-04-045, D.13-01-024, and D.13-04-017.

Estimated 2013-2014 amount for AC Cycling (aka Summer Discount Plan (SDP)) includes 2/3 of D.12-04-045 but does not include the Commission approved funds of $1.9 Million for Residential SDP and $693,000 for Commercial SDP, as approved in D.13-04-017. The $1.9 Million is moved to Local Marketing and the $0.6 million was specifically noted as a one-time project.

Auto DR includes the $5M approved in D.13-04-017 with the stipulation that $4.2 Million must go toward incentives. The program must follow the rules of D12-04-045.

(END OF ATTACHMENT 4)