Decision **PROPOSED DECISION OF ALJ HYMES (Mailed 5/3/2016)**

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 ADOPTING BRIDGE FUNDING FOR 2017 DEMAND RESPONSE PROGRAMS AND ACTIVITIES

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DECISION ADOPTING BRIDGE FUNDING FOR 2017 DEMAND RESPONSE PROGRAMS AND ACTIVITIES

Summary

This decision approves proposals, as modified below, for 2017 demand response programs and activities for Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (SCE). The following budgets are authorized: $59.9 million for PG&E, $23.8 million for SDG&E, and $56.28 million for SCE. We also adopt a proposal from SCE, as revised below, to address the natural gas leak at the Aliso Canyon Gas Storage Facility and authorize a budget of $8.7 million.

1. Background

Decision (D.) 14-12-024, established the steps toward 2018, the year that full implementation of the bifurcation of demand response into load modifying and supply resources, as well as the full integration of supply resources into the California Independent System Operator (CAISO) energy market, will begin. In D.14-12-024, the Commission declared that "the 2016 and 2017 years are viewed as transitional years." The Commission stated a desire to incrementally improve demand response programs during the transitional years. While D.14-12-024 confirmed that one of the steps toward full implementation of bifurcation would include the adoption of a decision authorizing bridge funding for 2017, the Commission emphasized that as transitional years, 2016 should begin to see small steps toward bifurcation and 2017 should see bigger steps.

On September 15, 2015, the assigned Commissioner and Administrative Law Judge (ALJ) jointly issued a Ruling providing guidance for 2017 demand response program proposals to be filed by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California

Edison Company (SCE) (jointly, the Utilities). On February 1, 2016, the Utilities complied with the Guidance Ruling and each filed a 2017 demand response program proposal. Parties filed comments on the proposals on March 2, 2016. On March 16, 2016, the ALJ issued a ruling requesting additional information from the Utilities. The Utilities complied, filing timely responses on March 24, 2016. This decision addresses the 2017 demand response proposals and related comments on the proposals.

On March 23, 2016, the assigned Commissioner issued a Ruling directing demand response activities to help mitigate a natural gas leak at Aliso Canyon Storage Facility. The Aliso Canyon Ruling directed SCE to file proposals to intensify demand response efforts in the geographic areas most affected by the leak and to mitigate the impact of reliability issues arising from the leak. SCE filed its proposal on April 4, 2016. Parties filed responses to the proposal on April 12, 2016. This decision addresses SCE's proposal and party comments.

2. Overview of 2017 Guidance to Utilities

As previously stated, a Guidance Ruling directed the Utilities to file proposals for 2017 demand response program bridge funding and provided guidance to the Utilities regarding the contents of the proposals. The guidance was based on prior Commission decisions in this and related demand response proceedings and comments in response to an August 6, 2015 Ruling providing preliminary guidance. The Ruling provided the following proposal framework to the Utilities:

A. Program changes to enable market integration:

1. Feasibility of CAISO market integration for each program;
2. A plan to complete the integration of reliability programs into the Reliability Demand Response Resource CAISO market no later than May 1, 2017; and
3. Recommendations of Pilots to address over-generation from renewables.

B. Overall program improvements:

1. Revised cost-effectiveness analyses, using 2010 Protocols, shall be included if proposed changes result in changes to cost-effectiveness inputs;
2. Utilities should improve Automated Demand Response (ADR), Technology Incentives/ Technical Assistance Programs; and
3. Budget reductions should be considered, where appropriate.

C. Contents of the Portfolio:

1. Complete budgets;
2. Anticipated 2017 load impacts (in megawatts);
3. A list of all demand response related programs and incentives established external to Application (A.) 11-03-001 et al.; and
4. A proposed schedule to consolidate all demand response programs and incentives, not including dynamic pricing programs, into one portfolio.

D. Miscellaneous Items:

1. Senate Bill (SB) 1414/Public Utilities Code Section 380.5(a)(3) and (b) requirements, including barriers or unintended consequences; and
2. An explanation of whether to include funding for studies to advance the Commission's demand response goals.

3. Overview of Utility 2017 Response Program Proposal

An overview of each demand response utility's proposal for 2017 demand response programs and activities is provided below using the same framework as that presented in the Guidance Ruling.

3.1. PG&E

The following is an overview of PG&E's proposal for 2017 demand response activities and bridge funding.

A. Program changes to enable CAISO market integration:

1. Feasibility of CAISO market integration for each program.

- The Base Interruptible Program (BIP) is most compatible with the market. PG&E's systems need to be updated to support dispatch of this program in the real-time market. BIP has MWs unable to be integrated;
- The Aggregator Managed Portfolio (AMP) program will not be continued in 2017, but customers will be encouraged to enroll into the Capacity Bidding Program (CBP);
- CBP is able to integrate into the CAISO market with some tariff modifications;
- The Demand Bidding Program (DBP) is not compatible with market due to the timing of event notifications. PG&E proposes to eliminate DBP; and
- The design of the SmartAC program makes it favorable for market integration because of a fast response time, but the volume of participants makes resource management challenging. PG&E contends that enabling the market integration of SmartAC requires the use of statistical sampling methodology.

2. The integration of reliability programs: PG&E plans to complete the integration of BIP, a reliability program, into the Reliability Demand Response Resource (RDRR) CAISO market no later than May 1, 2017.

3. Pilots to address over-generation from renewables: PG&E will continue the work on its Excess Supply demand response pilot.[1] PG&E will merge its supply side demand response pilot with its Transmission and Distribution demand response pilot to test the ability of third parties and customers to provide available load relief to PG&E in a manner that not only can be used as non-wires alternative solutions for local distribution reliability issues but also meets resource adequacy requirements and is integrated into the CAISO markets.

B. Overall program improvements:

1. Cost-effectiveness Analysis: PG&E performed cost-effectiveness analyses for each program individually and for its entire portfolio using the 2010 Protocols and an updated avoided cost. The total resource cost (TRC) test benefit/cost ratios are 1.0 for BIP, CBP and SmartAC, and 0.9 for the permanent load shifting program and the portfolio.
2. ADR Improvements: PG&E proposes the following changes to its ADR program: a) Revise the 60-40 percent incentive split model to a 100 percent incentive paid up front; b) Reduce the incentive cap from 100 percent to 50 percent of total project implementation cost, for large commercial and industrial customers; c) Offer an additional option of incentives for small business customers; and d) Increase choice by expanding the list of qualifying programs.
3. Budget Decreases: PG&E proposed an overall decrease of $6.8 million annually compared to annual funding during the years 2012-2016. This translates into the following budget revisions, by category:

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[1] The excess supply demand response pilot was originally approved in D.14-05-025.

- $100,000 decrease in reliability program funding due to inactivity;
- $5.3 million increase in price responsive program funding from increased incentive amounts created by shifting customers from the AMP program to the CBP;
- decreased AMP budget by $440,000 due the termination of the program, $30,000 is required to implement the termination of the current AMP contracts;
- $5.3 million decrease in emerging and enabling programs fund due to ADR changes;
- same funding level in pilot category;
- $0.54 million decrease in EM&V due to the termination of DBP and AMP;
- $0.87 million decrease in ME&O due to termination of DBP;
- $2.9 million increase in DR System Support Activities for CAISO market integration; and
- no additional funding for special projects.

C. Contents of the Portfolio:

1. PG&E requests a total budget of $49.29 million for 2017.
2. PG&E states that the proposed program improvements for 2017 will have minimal impacts on the aggregate load reduction; the ex-ante load impacts filed on April 1, 2015[2] remain a reasonable basis for the 2017 projection. PG&E anticipates a load impact of 557 MW for all demand response programs in August 2017.

[2] The *ex ante* load impacts were amended on June 12, 2015.

3. PG&E's proposal includes a list of all demand response related programs and incentives established external to A.11-03-001 et al. Only the BIP and AMP incentives were approved externally.
4. PG&E proposes a schedule to consolidate all demand response programs and incentive into one portfolio, not including dynamic pricing programs. As noted above, only the BIP and AMP incentives have not been included. PG&E proposes to include the BIP incentives in the 2018-2020 program application and to eliminate AMP.

D. Miscellaneous Items:

1. PG&E contends that the demand response programs comply with the consumer protections adopted in SB 1414 and codified in Public Utilities Code Section 380.5(a)(3) and (b). PG&E provides an overview of how each program meets these requirements.
2. PG&E recommends that the Commission continue to authorize a $1 million study fund to promote demand response. PG&E contends that follow up work on the Potential Study needs to be performed and this is the venue. PG&E also recommends that unused funds be returned to ratepayers if not used by June 2019.
3. PG&E states that it is developing an educational plan in response to AB 793, to inform customers of available incentives for the acquisition of energy management technology.

3.2. SDG&E

The following is an overview of SDG&E's proposal for 2017 demand response activities and bridge funding.

A. Program changes to enable market integration:

1. Feasibility of CAISO market integration for each program.

- While CBP already meets most of the CAISO market requirements, SDG&E proposes to make three adjustments to allow for better alignment;
- SDG&E also proposes that a change of the customer event notification timeframe from 30 to 20 minutes will allow BIP to meet the CAISO requirement for real-time curtailment. However, SDG&E contends that the minimum load per load serving entity requirement may be a barrier; and
- SDG&E identified several barriers for integrating its AC Cycling program into the CAISO market: an existing 25 percent error in the day-ahead baseline and the upgraded demand response registration system. SDG&E proposes changes to enable the program to be CAISO compliant.

2. The integration of reliability programs: SDG&E anticipates that the BIP will be integrated into the CAISO market during 2016 with full compliance with the RDRR requirements in the 2017 program year.
3. Pilots to address over-generation from renewables: SDG&E proposes three new pilots: a) a $700,000 over generation pilot to determine whether distributed storage facilities can effectively and economically addresses the excessive export of distributed solar to the grid during non-peak periods and the lack of flexible generation during demand response events; b) a $150,000 Summer Saver program programmable communicating thermostat pilot to offer new customers installing this technology with the opportunity to participate in the revised summer saver program; and c) $187,000 pilot for a specifically tailored program to replace DBP for the Navy. SDG&E proposal includes the 2017 Demand Response Auction Mechanism pilot and, despite previously approved funding, SDG&E requests an additional $1.5 million.

B. Overall program improvements:

1. Cost-effectiveness Analysis: SDG&E performed cost-effectiveness analyses for four of its programs. The TRC test benefit/cost ratios are 0.82 for Summer Saver, 0.87 for its Peak Time Rebate and Small Customer Technology Deployment (SCTD); 0.94 for its CBP and 0.59 for its BIP. SDG&E conducted two alternate scenarios because it considers the value of demand response to be in flux due to the transition to supply side resource. Both of the scenarios resulted in higher TRC benefit / cost ratios.

2. ADR Improvements: SDG&E proposes changes to its technology incentives program and its SCTD program. SDG&E proposes to put an incentive cap of 50 percent of the total eligible project cost on this program to encourage customers to maximize load shed during events, which will maximize benefits in order to offset the technology investment. In addition, SDG&E proposes that 100 percent of the incentive will be paid after installation, load shed test, and enrollment. SDG&E proposes that the SCTD program encourage participation in a dynamic pricing or time of use rates at enrollment in exchange for a no-cost or subsidized technology and support the 2017 Summer Saver programmable communicating thermostat pilot, which will be made available to direct access and community choice aggregator customers.

3. Budget Decreases:

   SDG&E proposes an overall Increase of $0.2 million or 0.1 percent annually compared to 2016 funding, but this budget added the Summer Saver program not previously included in the portfolio. SDG&E states that it has made every effort to be responsive to the Guidance Ruling's encouragement to decrease costs. After accounting for the Summer Saver program, these efforts resulted in an 11.4 percent decrease compared to 2016:

- decrease in reliability programs funding due to low customer participation and therefore a decreased customer incentive budget;
- increase in price responsive programs funding by the addition of the $2.5 million Summer Saver Program, which is balanced out by decreases in the terminated DBP and the decreased incentives in the CBP;
- $1.9 million decrease in emerging and enabling programs fund due to decreases in TI and SCTD incentives;
- increased funding level in pilot category due to four new pilots;
- $1.3 million decrease in Marketing, Education and Outreach due to a change in program implementation;
- $1.5 million increase in Demand Response System Support Activities, primarily for CAISO market integration; and
- $0.6 million increase in the Special Projects category to encourage participation in the permanent load shifting (PLS) program.

C. Contents of the Portfolio:

1. SDG&E requests a total budget of $20.8 million for 2017.
2. SDG&E filed a load impact forecast on April 1, 2015 for all of its demand response programs. SDG&E notes that its proposed changes to the Summer Saver program will likely affect the forecast. For example, SDG&E estimates that removing the lowest 20 percent of performers from the program will decrease the forecast by two percent. SDG&E's proposal includes a table of load impacts used in the cost-effectiveness calculations, which indicates a load impact of 53.8MW for all SDG&E demand response programs in August 2017.

3. SDG&E's proposal includes a list of all demand response related programs and incentives established external to A.11-03-001 et al.: the Scheduled Load Reduction Program and the Rolling Blackout Reduction Program.

4. SDG&E proposes to keep both the Scheduled Load Reduction Program and the Rolling Blackout Reduction Program in its general rate case, where the programs are currently funded. Additionally, SDG&E proposes to include funding for the Summer Saver program in the 2017 demand response portfolio. SDG&E proposes that all supply resource programs (except for the Scheduled Load Reduction Program) be integrated into the demand response portfolio and all load modifying demand response programs be integrated into the general rate case.

D. Miscellaneous Items:

1. SDG&E explains that existing consumer protection provisions that exist under SDG&E Tariff Rule 32 provide consumer protection sufficient to meet the requirements of Public Utilities Code Section 380.5(a)(3) and (b). SDG&E provides an overview of how each program meets these requirements.

2. SDG&E supports the continuation of Commission authorization of funding for studies to advance demand response. SDG&E contends however that the Utilities and other stakeholders should be provided opportunities to participate in the evaluation process to ensure the study is accurate and achieves its intended purpose.

3. SDG&E has no specific proposal for the implementation of AB 793 but anticipates that the requirements will be addressed through the Integrated Demand Side Management programs in the Commission's energy efficiency proceedings.

3.3. SCE

The following is an overview of SCE's proposal for 2017 demand response activities and bridge funding.

A. Program changes to enable market integration:

1. Feasibility of CAISO market integration for each program.
    - SCE states that it integrated the following programs into the CAISO market in June 2015: CBP, AMP, BIP, API and Summer Discount Plan. These five programs represent 90 percent of SCE's portfolio. Due to several issues, 150 of the 1,314 MW represented by these five programs could not be registered into the CAISO market. That aside, SCE considers these five programs fully integrated;
    - SCE offers additional changes for 2017 including new telemetry requirements for AMP customers, streamlining and event notification modifications for CBP, and improvements to the PeakTime Rebate (PTR) incentive program; and
    - SCE does not plan to integrate its DBP due to the large scope of changes necessary; SCE has determined that integrating DBP as a standalone resource would provide a small number of megawatts for an unreasonable cost.
2. The integration of reliability programs: SCE has completed the integration of its reliability programs into the RDRR CAISO market.
3. Pilots to address over-generation from renewables: SCE proposes a pilot program to study the application of an energy storage technology, specifically pumped water storage.

B. Overall program improvements

1. Cost-effectiveness Analysis: SCE performed cost-effectiveness analyses for the CBP, the only program where proposed changes would alter the cost-effectiveness inputs. SCE used the most recent E3 avoided cost model. The TRC cost benefit ratios are 1.52 for the day-of CBP and 1.46 for the day-ahead CBP.
2. ADR Improvements: SCE proposes to make moderate changes to its ADR program: a) Eliminate the 60/40 incentive structure; b) Reduce the incentive cap from 100 to 50 percent of total cost; and c) Reduce the incentive to $150/kW.
3. Overall Decrease of nearly $42 million annually compared to annual funding in 2015-2016:
   - $691,000 decrease in reliability program funding due to the elimination of remote terminal units for BIP;
   - $17.3 million decrease in price responsive program funding due to the termination of DBP and program changes in CBP, PTR, and Summer Discount Program;
   - $7.3 million decreased AMP budget due to decreased capacity incentive costs for the AMP contracts;
   - $7.2 million decrease in emerging and enabling programs fund due to ADR changes;
   - $1 million pilot funding increase because no pilots were performed in 2016;
   - no changes in EM&V;
   - $4.2 million decrease in ME&O due to elimination of DBP and circuit saver, and reduced marketing for PTR and PLS; and
   - $1.4 million decrease in DR System Support Activities due to reduced labor costs and because the upgrades requested have been completed.

C. Contents of the Portfolio

1. SCE requests a total budget of $44.28 million for 2017.
2. SCE's proposal includes its load impact forecasts for all demand response programs for the 2017 program year based on 2014 program performance.
3. SCE's proposal includes a list of all demand response related programs and incentives established external to A.11-03-001 et al. Incentive levels for SCE's tariff programs are determined in Phase 2 of SCE's General Rate Cases. Integrated Demand Side Management funding is filed in the energy efficiency portfolio application. SCE proposes that these funding sources continue as is.

D. Miscellaneous Items

1. SCE contends that the demand response programs comply with the consumer protections adopted in Senate Bill 1414 and codified in Public Utilities Code Section 380.5(a)(3) and (b).
2. SCE states that it sees no compelling reason to ask the Commission to discontinue the $1 million demand response research funding during the 2017 bridge funding period.
3. SCE states that it awaits Commission guidance on Assembly Bill (AB) 793 but recommends that the Commission resolve the following issues:
   a) determination of which proceeding should implement the statute; b) definition of an energy management technology; c) how program costs and incentives will be funded: d) requirements for the program design; and e) metrics, parameters, and scope of the education plan.

4. Responding to the Aliso Canyon Gas Storage Facility Leak

On March 23, 2016, the assigned Commissioner issued a Ruling in this proceeding directing SCE to take immediate steps to enhance their demand response efforts in response to the Aliso Canyon Gas Storage Facility (Aliso Canyon) leak. The Aliso Canyon Ruling explained that safety and ratemaking issues, and broader implications of the natural gas leak at Aliso Canyon, will be addressed in other proceedings. Certain actions may be more appropriate within Rulemaking 13-09-011 to mitigate the impact of reliability issues arising from Aliso Canyon. Several offerings within the demand response portfolio may reduce or shift the demand for electricity in the geographic regions most affected by the leak at Aliso Canyon. Specifically, the Aliso Canyon Ruling directed SCE to file a proposal increasing participation in certain demand response programs, conducting a demand response auction targeted at affected areas, and offering incentives for programmable thermostats. Additionally, the Aliso Canyon Ruling directed SCE to respond to four questions.[3] The Aliso Canyon Ruling also invited SCE to offer alternate proposals. Parties were invited to comment on SCE's proposal and respond to the same four questions.

SCE filed its proposal on April 4, 2016 in compliance with the Aliso Canyon Ruling.[4] On April 12, 2016, parties provided comments to the proposal.[5]

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[3] The four questions addressed issues regarding cost-effectiveness of the proposals, suspension of the two percent reliability program cap, a customer auction mechanism, and the reconsideration of current demand response program rules.

[4] On April 4, 2016, the Office of Ratepayer Advocates (ORA), OhmConnect, PG&E, and Sierra Club/Environmental Defense Fund filed comments to the questions posed in the Ruling.

5. Issues Before the Commission

The purpose of this decision is two-fold: 1) authorize bridge funding and consider proposals for 2017 demand response programs and activities pursuant to D.14-12-024 and the Guidance Ruling; and 2) approve actions for SCE to execute in order to intensify demand response efforts in the geographic areas most affected by the Aliso Canyon leak and to mitigate the impact of reliability issues arising from the leak.

We note that during the course of developing the record for 2017 bridge funding, parties have made several references to future demand response program years and propose recommendations for future years. We will consider these comments, in addition to future comments, in a forthcoming decision regarding 2018 and beyond demand response program years.

In reviewing the proposals, party comments, and additional filings in response to the Guidance Ruling and the Aliso Canyon Ruling, the issues before the Commission are:

1. Whether the proposals for 2017 demand response activities filed by the Utilities are reasonable pursuant to the guidance given in D.14-12-024 and the September 15, 2015 Guidance Ruling and whether the proposals should be approved;
2. Whether the funding requested by the Utilities for 2017 demand response activities is reasonable and should be approved; and

[5] Parties filing comments to the SCE proposal include the California Energy Storage Association (CESA), CAISO, the California Large Energy Consumers Association (CLECA), the Joint Demand Response Parties, and Nest Labs.

3. Whether the proposal filed by SCE for mitigating the impact of reliability issues arising from the Aliso Canyon Storage facility leak is reasonable and should be approved.

6. Discussion and Analysis

6.1. SCE Proposal to Mitigate Impact of Aliso Canyon Leak

We approve SCE's Aliso Canyon Proposal, as revised below, to increase the use of demand response programs in order to address the impacts of the gas leak at the Aliso Canyon Gas Storage Facility (Aliso Canyon). We find that the Aliso Canyon Proposal, as revised below, meets the requirements of the March 23, 2016 Ruling in that it focuses on reliable demand response, it targets the geographic areas where electric reliability may be at risk because of the anticipated gas shortage, it focuses on increasing demand response in 2016 and 2017, and it is coordinated with 2017 Bridge Funding. Additionally, we authorize SCE to proceed with a custom Demand Response Auction Mechanism (DRAM), as described within. If SCE chooses to exercise this option, it must meet with Energy Division, the CAISO and other stakeholders to, within 10 days of the issuance of this decision, to begin preparations.

In the March 23, 2016 Ruling, we emphasized that safety and ratemaking issues, and broader implications of the natural gas leak at Aliso Canyon would be addressed in other proceedings. Consistent with efforts of other Commission activities regarding Aliso Canyon, we direct SCE to open a balancing account so that the Commission can track the specific expenses for the approved proposals.

SCE proposes the following changes and additions to its demand response programs in response to the March 23, 2016 Ruling.

- **Summer Discount Plan:** Increase marketing, education and outreach efforts for their Summer Discount Plan by using $2.8 million of currently available 2016 funds to gain an additional 8 to 14 megawatts of load reduction.[6] Requests an increase of $4.178 million in 2017 funds to achieve an additional load reduction of 10-16 megawatts.[7] To address the current program attrition concern, SCE proposes that the Commission establish a reduced minimum threshold for economic dispatch of 20 hours for SDP in 2016 and 2017.
- **Peak Time Rebate:** Withdraw its request to terminate certain Peak Time Rebate (PTR) programs in 2016. Thus, in order to delay the discontinuance of PTR and PTR ET (Enabling Technology) to 2017, SCE requests $600,000 in additional funding. SCE also requests an additional $1.647 million to provide a $75 rebate to 28,000 customers who purchase and install an eligible thermostat for their PTR Direct Load Control program (PTR-ET DLC).
- **Demand Response Auction Mechanism:** SCE did not propose a custom Demand Response Auction Mechanism (DRAM) in the specified geographic areas or adjust the focus of the 2017 DRAM pilot but recommends that the Commission direct the Energy Division to facilitate a discussion between SCE, the CAISO, and other stakeholders to determine whether an additional DRAM-like auction in support of the Aliso Canyon effort would be useful for 2017 and what its parameters would

[6] SCE Aliso Canyon Proposal at 4.

[7] The $4.178 million includes $3.178 million in incremental Aliso Canyon SDP program budget expenses and an additional $1 million for other local marketing. (*See* SCE Proposal at Table 1.)

entail. SCE would request any necessary funding at a later date.

- **SCE Demand Bidding Proposal:** SCE requests an additional $255,000 for the continuation of the Demand Bidding Program (DBP) and proposes postponing the termination of this program to 2018.[8]
- **Base Interruptible Program and Agricultural Pumping Interruptible:** SCE requests using existing Base Interruptible Program (BIP) funds to gain five megawatts of incremental load in 2016. SCE also requests an additional $42,000 in funding for the Agricultural Pumping Interruptible program (API) in 2017 to obtain four megawatts of load reduction.

Summer Discount Plan

As described below, we modify SCE's proposal to increase enrollment in its Summer Discount Plan with targeted marketing to customers in the Los Angeles (LA) Basin Local Capacity Area with high usage patterns. Additionally, we approve the request to reduce the minimum threshold hours to 20, for both 2016 and 2017. Consistent with D.16-03-031, we direct SCE to establish a balancing account to track the authorized expenses in this decision. We authorize SCE a budget of $2.8 million using current 2016 funding and $3.178 million of additional 2017 funding for Summer Discount Plan expenses.

SCE explains that for program year 2016, it will target approximately one million residential and commercial customers in high density areas with interval

[8] In SCE's 2017 bridge funding proposal, SCE requested to terminate DBP beginning in 2017.

data high enough to indicate air conditioner usage.[9] SCE plans to use the same criteria to target 1.6 million residential and commercial customers in 2017.

The March 23, 2016 Ruling requires that SCE proposals should focus on reliable demand response that can be quickly deployed, target the geographic areas at risk, focus on 2016 and 2017, and be coordinated with the 2017 budget. AC Cycling programs are relatively fast and typically provide reasonable performance. Hence, the Summer Discount Plan proposal meets the requirement of reliable demand response that can be quickly deployed. We find that because SCE's proposal focuses solely on program years 2016 and 2017 and is coordinated with the 2017 budget request, it meets the time requirements of the March 23, 2016 Ruling. We next discuss the remaining requirement, targeting the geographic areas at risk.

ORA maintains that SCE's proposal is not in compliance with the Ruling's directive to intensify efforts in the areas most impacted by the gas leakage at Aliso Canyon.[10] SCE asserts that "because of the system-wide impact of the proposed limitations on the use of gas, efforts to enhance demand response should not prioritize the geographic areas covered by Aliso Canyon." The CAISO disagrees with this statement maintaining that demand response resources in the LA Basin should be prioritized. CAISO references the Aliso Canyon Risk Assessment Technical Report and underscores its finding that the amount of gas curtailment that can be managed depends on a number of factors including local transmission contracts within CAISO's Southern California system. The report found that generating resources served by Aliso Canyon

[9] SCE Aliso Canyon Proposal at 4.

represent nearly 70 percent of the local capacity resources identified in CAISO's local capacity requirements for the LA Basin. The report cautions that if these resources are limited or curtailed, it may be necessary to interrupt electric load in the local capacity area to avoid cascading blackouts.[11] As we directed in the March 23, 2016 Ruling, all Aliso Canyon proposals shall prioritize the geographic regions affected by the gas leakage.

In comments to the proposed decision, SCE cautions that prioritizing the LA Basin Local Capacity Area should be applicable only to marketing efforts and that other efforts, such as reducing the number of dispatch hours for the Summer Discount Plan, cannot be reasonably limited to the LA Basin Local Capacity Area because it would be complex and confusing for customers. SCE explains that tariffs, which define the requirements of a program, educate customers on rates and terms of service and requiring different terms for customers depending on their location could be confusing, create delays, and complicate market integration. Given the circumstances and that fact that these program changes are temporary, we will not require SCE to establish different terms for these program customers depending upon their location. However, all marketing efforts shall focus solely on customers in the LA Basin Local Capacity Area.

Nest contends that the effort to increase participation in the Summer Discount Plan offers an opportunity to move beyond the current limited scope of the program.[12] Nest explains that the current program relies on the use of direct load control devices that can be overridden by a customer and proposes that

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[10] ORA Comments at 2-3.

[11] CAISO Comments at 2.

[12] Nest Comments at 3.

customers leaving the Summer Discount Plan program are encouraged to enroll in the PTR-ET-DLC and are offered a smart thermostat as part of the enrollment. However, the record of this proceeding has no data to confirm that this would result in increased participation and/or performance.

Lastly, we discuss SCE's proposal to reduce the number of economic dispatch hours from forty to twenty hours. SCE explains that a recent Summer Discount Plan study indicates that the increase in program dispatches has led to an increase in customer-requested attrition.[13] SCE contends that by establishing 20 hours as the minimum threshold, it would be able to retain 13-17 MW from the expected attrition at 40 hours of dispatch.[14] ORA supports SCE's proposal, but requests the Commission to limit this to program years 2016 and 2017 only.[15]

We find the requested reduction of the economic dispatch hours to 20 to be reasonable; a decrease in the minimum threshold should decrease the rate of attrition. Furthermore, as stated in the March 23, 2016 Ruling, program changes in reaction to the gas leakage at Aliso Canyon are only applicable to the 2016 and 2017 program years; we confirm that the reduction in hours only applies through program year 2017.

We now focus on the attrition rate and its relationship with marketing. SCE explains that it initially reduced its funding request in its 2017 Proposal because it anticipated Summer Discount Plan enrollment to decrease *significantly* (emphasis added) due to a high rate of event-related attrition and less spending

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[13] SCE Aliso Canyon Proposal at 6.

[14] SCE Aliso Canyon Proposal at 7.

[15] ORA at 4.

on large scale enrollment campaigns."[16] In response to the Aliso Canyon leak, SCE proposes to increase Summer Discount Plan marketing efforts in 2016 using currently available funding. SCE also proposes to increase 2017 funding for Summer Discount Plan marketing campaigns, as well as program administration and purchase and installation of direct load devices. According to SCE's Aliso Canyon Proposal, for 2017, SCE requests $1 million additional funds solely for marketing and an additional $3.178 in incremental funds for the Summer Discount Plan program budget.[17]

SCE does not provide any evidence that the additional $1 million for marketing will alleviate the attrition rate or increase customer participation or performance levels. Hence, we deny the request to authorize the additional $1million for marketing the Summer Discount Plan program.

We find that the revised Summer Discount Plan proposal, focusing only on the LA Basin Local Capacity Area, meets the requirements of the March 23, 2016 Ruling. It focuses on increasing participation in 2016 and 2017 and is focused on the LA Basin area. We therefore find it reasonable to adopt SCE's Summer Discount Plan proposal, with the additional requirement to focus marketing efforts on the LA Basin area.

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[16] SCE Aliso Canyon Proposal at 5.

[17] *Id*. at Table 1.

In D.16-03-031, the Commission directed Southern California Gas Company to establish a balancing account, in order to protect customers by segregating revenues associated with Aliso Canyon that might be subject to refund in the future.[18] For consistency, we direct SCE to establish a balancing account so that the Commission is able to appropriately track the expenses we authorize in this decision. We direct SCE to record the additional 2016 and 2017 Summer Discount Plan expenses in this balancing account.

Peak Time Rebate

As described below, we adopt the proposed changes to SCE's PTR program and authorize the recording of additional 2017 PTR expenses up to a cap of $2.25 million, as described below.

SCE proposes to withdraw its request to terminate its PTR and PTR Enabling Technology programs (PTR and PTR-ET) in 2016 to avoid risks associated with making system changes during the summer season and mitigate customer confusion or dissatisfaction.[19] SCE proposes to discontinue PTR and PTR-ET in 2017, instead, and requests $600,000 in additional funding for that purpose. SCE explains that it had originally planned to discontinue these two programs due to low per-customer savings, poor cost effectiveness, and low dispatch flexibility. SCE notes that Advice Letter 3323-E filed on December 9, 2015 requesting approval to discontinue PTR and PTR-ET in 2016 has been suspended. ORA opposes the continuation of these programs because SCE proposes no changes to them.[20] We agree with ORA that SCE makes no

[18] D.16-03-031 at 3.

[19] SCE Aliso Canyon Proposal at 10.

[20] ORA Comments at 5.

attempt to improve the programs. However, given the suspension of the December 9, 2015 SCE Advice Letter to terminate these two programs and the fact that SCE has not begun the required system changes and outreach for the discontinuance of PTR and PTR-ET, we find it reasonable to allow the continuance of this program through 2016. We also find the budget request of $600,000, to fund the discontinuance of the PTR and PTR-ET in 2017, to be reasonable.

SCE also requests an additional $1.65 million to provide a $75 rebate to 28,000 customers who purchase programmable communicating thermostats (PCTs) and enroll in SCE's PTR Direct Load Control program (PTR-ET DLC). SCE claims it can increase enrollment in the program by up to 28,000 customers by program year 2017. Furthermore, SCE states that it performed a cost-effectiveness analysis for this program and the results of the Total Resource Cost cost/benefit ratio was 1.0. SCE asserts this result exceeds the demand response TRC threshold of 0.9 and is therefore cost-effective.[21] ORA argues that the Commission should consider other cost-effectiveness tests such as the Program Administrator Test (PAC) to determine the impact of the rebate and other changes on the cost-effectiveness of this program. In D.12-04-045, the Commission stated that the TRC, PAC, and RIM each provide a valuable perspective but our approach has been to focus primarily on the TRC and use the PAC and RIM when the context makes sense.[22] We will follow the same approach in the 2017 bridge funding and the approval of proposals to mitigate the effects of Aliso Canyon. Hence, we find the PTR-ET DLC to be cost-effective.

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[21] SCE Aliso Canyon Proposal at 13, Footnote 17 referencing D.12-04-045 at 44.

Nest proposes increasing customer rebates from $75 to $100 for the purchase of PCTs and enrollment in SCE's PTR-ET DLC program, contending that lowering the incremental cost to customers will lower barriers to entry. Nest also proposes to allow SCE to expand the PTR-ET DLC target number to 50,000 customers over two years. Nest provides no evidence to support its conclusion that a $100 rebate would provide higher participation rates than a $75 rebate or that such an increase would result in 50,000 or more customers participating. Furthermore, the record of this proceeding does not include a cost-effectiveness analysis of the program with the $100 rebate. Nest further recommends that SCE coordinate its demand response efforts with the Energy Savings Assistance Program and the Energy Efficiency Program. Specifically, Nest proposes that SCE target ten percent of Energy Savings Assistance Program customers for direct install of programmable communicating thermostats. Nest also proposes that SCE offer all customers opting out of the Summer Discount Program the alternative of enrolling in PTR-ET DLC, with a rebate at the level adopted in this decision. We agree that SCE should make every effort to coordinate its demand response programs with its other related programs. The scope of this proceeding does not allow us to direct SCE to take action or authorize them funding for programs outside of the demand response programs. However, we encourage SCE to pursue these recommendations as well as any other potential for coordination between demand-side programs.

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[22] D.12-04-045 at 43.

We find the changes to the PTR-ET DLC to be reasonable. The proposed changes to the program provide customer incentives for the purchase of a programmable communicating thermostat in combination with enrollment in the PTR-ET DLC tariff, thus meeting the requirements of the March 23, 2016 Ruling. We adopt the proposed changes to the PTR, targeting 28,000 customers, and authorize SCE to track in a balancing account up to an additional $2.25 million in demand response funding in 2017, which includes $1.65 in rebate costs, rebate processing and program administration, $300,000 for system changes and labor for decommissioning PTR and PTR-ET in 2017, and $303,000 for marketing and education.

Custom Demand Response Auction Mechanism

As discussed further below, we authorize SCE to conduct a custom stand-alone DRAM. Should SCE elect to exercise this option, it should meet with Energy Division, the CAISO and other stakeholders, within ten days of the issuance of this decision to begin preparations. The auction must begin with the same provisions of the 2017 auction and contract, while adapting to the five modifications in Table 1 below. Furthermore, we deny the request by EDF and Sierra Club to adopt the September 2015 enforcement and monitoring proposal from Energy Division staff; that proposal has not been adopted by the Commission. Given the narrow focus of this decision, it is not appropriate to address the staff proposal at this time.

The March 23, 2016 Ruling directed SCE to propose "conducting a custom demand response auction mechanism targeted at the areas most affected, or adjusting the focus of the current auction mechanism." SCE did not recommend a specific custom auction or adjusting the current auction, contending that the current provisions of the demand response auction mechanism pilot are not useful for addressing potential reliability risks stemming from the Aliso Canyon leak, such as bringing new demand response customers (resources) into the market and providing new fast-response demand response resources.[23] Instead, SCE recommended that the Energy Division facilitate a discussion between the stakeholders, the CAISO, and SCE to review the experience, performance and impact of the current pilots after the summer of 2016 and determine whether an additional custom mechanism would be useful in support of the Aliso Canyon effort in 2017.[24]

While SCE argued that the 2017 auction pilot is not useful for addressing potential reliability risks stemming from the Aliso Canyon leak, SCE presented no argument that a custom or adjusted auction mechanism would not be relevant or appropriate. SCE suggested that the Commission wait until after the Commission receives the results of the 2016 pilot and develop a custom auction based on that information. However, waiting until the end of 2016 is not an option.

ORA requests that if the Commission intends to embark on a custom auction, it should be a separate stand-alone auction focused to meet the needs of the areas affected by the Aliso Canyon gas leakage.[25] ORA and Joint Demand Response Parties agree with SCE that the auction currently underway is not specific to meeting the Aliso Canyon needs. Joint Demand Response Parties recommend that for a successful custom auction to be designed, the Commission must begin a public stakeholder process immediately to create an enhanced

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[23] SCE Aliso Canyon Proposal at 9.

[24] *Ibid*.

[25] ORA April 4, 2016 Comments at 4 and Joint Demand Response Parties at 6.

auction that must make the criteria under which the utility would bid the resource into the wholesale market transparent to the third-party provider.[26] Furthermore, the Joint Demand Response Parties recommend that the Commission consider a procurement that is more durable than a single demand response season.[27]

We agree that the current auction mechanism is not appropriate to address the issues of Aliso Canyon and that a custom auction may be necessary to adequately address the potential shortages. Because SCE did not propose either a custom or adjusted auction mechanism, we use the latest 2017 auction pilot as a starting point.

We agree that a public stakeholder process may be appropriate for finalizing the specifics of a SCE custom auction mechanism. Hence, should SCE elect to exercise this option, we require SCE to hold a public meeting no later than 10 days from the issuance of this decision to finalize the aspects of a SCE custom auction mechanism. Furthermore, given the urgency of the matter and the need to move forward quickly, we provide a strong starting point for the stakeholders to begin. As noted by SCE, the current mechanism did not focus on recruiting new customers into the demand response portfolio or fast responding demand response. The current mechanism focused on the three demand response utilities' service area. Hence, we have included three modifications for the custom auction to address these characteristics. (*See* Table 1.) Additionally, we also require the use of a contract pro forma—allowing for up to a three-year contract—and a recommended timeline to address the Aliso Canyon issue in a

[26] Joint Demand Response Parties Comments at 6.

timely manner. The three-year contracts address the concern by the Joint Demand Response Parties that one-year procurement is not sufficiently durable to make a SCE custom DRAM viable. A three-year contract should express the durability and ensure reliable demand response will be available in the affected areas.

Because the customer auction mechanism should again prioritize efforts in the LA Basin local capacity area, we authorize a budget of $3 million for the auction mechanism, half of SCE's 2016 demand response auction mechanism budget. SCE is authorized to record 2016 and 2017 customer auction mechanism expenses in the balancing account established in this decision.

Lastly, the Joint Demand Response Parties assert that any action taken by the Commission to alter the auction in response to EDF and Sierra Club's proposal is legally inappropriate. EDF and Sierra Club request the Commission to ensure that any demand response procured to mitigate the effects of Aliso Canyon is not provided by natural gas-fired generation. EDF and Sierra Club contend that the custom auction should instead adopt the September 2015 enforcement and monitoring proposal from Energy Division staff.[28] The Commission has not made a determination on the Energy Division Staff Proposal. It is not appropriate to address the Staff Proposal in either a bridge funding decision or the issue regarding the gas leak at Aliso Canyon. We deny the request by EDF and Sierra Club to adopt the Staff Proposal in this decision. However, we underscore that the current DRAM pilots specify that only non-

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[27] *Ibid.*

[28] EDF and Sierra Club Comments at 2-3.

fossil generation and storage that meets certain greenhouse gas criteria are allowed to be coupled with a DRAM resource.

Table 1 **Required Modifications for SCE Custom DRAM**	
1) Geographically targeted to the LA Basin.	
2) Minimum of a 30-minute dispatch requirement.	
3) New resources only, defined as resources not currently participating in a Commission-regulated demand response activity.	
4) Contracts must be standard pro forma, and modified from the 2017 DRAM pilot contract.	
5) Use of a pre-defined advice letter timeline as indicated in the table below:	
Advice Letter Timeline	
SCE files Advice Letter with contract and any other relevant items from Decision	7/15/2016
Protests received	8/4/2016
SCE responds to protests	8/9/2016
Disposition Letter	8/18/2016
DRAM Request for Offers Issued	8/24/2016
DRAM Request for Offers closes	9/26/2016
Bidders notified of cure period	9/29/2016
Cure period ends	10/5/2016
Winning bidders notified	
Final contract sent for execution	10/26/2016
SCE files Advice Letter with contracts	11/23/2016
Energy Division Reviews AL with contracts	12/30/2016
Demand Response Providers register resources with CAISO	January - April/May
Deliveries commence	5/1/2017

SCE Demand Bidding Proposal

As described below, we authorize the continuation of SCE's DBP through 2017. However, we do not adopt the recommendation by CLECA to grant this continuation to PG&E and SDG&E. As we discussed earlier, Aliso Canyon proposals shall be focused only on the areas affected by the Aliso Canyon gas leakage.

In response to the March 23, 2016 Ruling, SCE requests to modify its 2017 bridge funding proposal for the DBP. In the 2017 proposal, SCE requests authority to retire its DBP effective January 1, 2017. SCE now requests to continue the DBP for the summer seasons of 2016 and 2017. SCE also requests budget authority of $225,000 to fund the program in 2017.

CLECA supports SCE's request to continue DBP and recommends that DBP should be continued for both SCE and PG&E. CLECA states that in 2015, SCE's DBP provided an average of 100 megawatts of demand response for each of the ten events called; each event ranged from 77 to 131 megawatts.[29] While noting that 78 percent of SCE's DBP load impacts are in the LA Basin, CLECA agrees with SCE that the focus should be broader than the LA Basin and suggests that PG&E maintain its DBP through 2017 in addition to SCE.[30]

We have previously determined that the demand response program changes adopted in this decision to address Aliso Canyon shall be targeted to the LA Basin. Hence, we deny the request by CLECA to allow PG&E to maintain its DBP to alleviate the potential gas shortages caused by Aliso Canyon.

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[29] CLECA Comments at 2 referencing the 2015 Load Impact Evaluation.

[30] CLECA Comments at 3.

Given the urgency of this matter, the fact that these resources are already in place, and the propensity of this program to perform, we grant the request of SCE to delay the elimination of DBP until 2018. The limited continuation of this program addresses the requirements that the program targets the affected geographic area in 2017 and can be quickly deployed. We authorize SCE to track up to an additional $255,000 in DBP expenses in 2017.

Base Interruptible Program and Agricultural Pumping Interruptible

We find the request of SCE to increase participation in BIP and AP-I to be reasonable and authorize the additional requested funding. We find the targeted marketing to potential customers should result in additional load impacts. As discussed further below, we deny the request to suspend the 2 percent cap on reliability programs.

In the March 23, 2016 Ruling, SCE was asked whether the Commission should suspend the requirement, established in D.10-06-034, that the Utilities may only meet two percent of its resource adequacy obligation with reliability (emergency) demand response. SCE further explained in its Proposal that a settlement agreement adopted by D.10-06-034 established the process for determining the Utilities' megawatt limit for reliability-based demand response. SCE stated that its current limit is 659 megawatts. SCE recommends that the Commission suspend the requirement for all of the Utilities, arguing that the Commission has been directed to take all actions to ensure the continued reliability of electricity supplies during the moratorium on gas injections into the Aliso Canyon Storage Facility.[31] SCE concludes that removing the cap would not

[31] SCE Aliso Canyon Proposal at 16.

likely revoke the progress that has been made on increasing price-responsive demand response.

PG&E cautions that a suspension to allow SCE to obtain additional emergency demand response resources should not occur at the expense of PG&E or SDG&E, or require them to reduce their emergency demand response resources. Furthermore, PG&E requests that the Commission treat additional emergency demand response obtained by SCE in response to Commission directives as not counting against the two percent cap calculated under the settlement. PG&E contends this would prevent the Commission's direction to SCE from reducing PG&E and/or SDG&E's reliability-based demand response.[32]

ORA does not oppose the request by SCE to increase customer participation in BIP or API, but asserts that there is no immediate need to raise the megawatt cap. ORA contends that even with the potential increase of nine megawatts for BIP and API, SCE is 57 megawatts below its share of the statewide cap.[33] Furthermore, ORA states that the Commission should not approve any generalized additional authorization of BIP and other reliability programs in areas not affected by the Aliso Canyon gas leakage.[34]

We approve the increased customer participation in BIP and API. However, we find that SCE has sufficient space under the two percent cap on reliability programs. At this time, we do not find it necessary to suspend the cap.

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32 PG&E Comments at 3.

33 ORA Comments at 3.

34 *Ibid*.

In its monthly Aliso Canyon report,[35] SCE is directed to inform the Commission if it approaches the two percent cap. We previously determined that all efforts to alleviate the impacts from the Aliso Canyon gas leakage shall be focused on the LA Basin, hence the request to suspend the two percent cap for PG&E and SDG&E is denied. SCE is authorized to track up to $42,000 in additional API 2017 funding.

6.2. Demand Response Program Activities and Budgets

As stated in the decision approving bridge funding for program years 2015 and 2016, bridge funding typically allows programs to continue, with the same activities and budget, for a short and specific period of time.[36] However, D.14-12-024 stated that because 2016 and 2017 are considered to be transitional years, the Commission anticipates larger steps toward bifurcation occurring in 2017. With this in mind, we approve the 2017 demand response program proposals filed by PG&E, SDG&E, and SCE with the following modifications:

- PG&E, SDGE, and SCE shall continue the Demand Response Auction Mechanism pilot in 2017. Until further notice, after the Commission is able to gather and analyze performance from the first two pilots, the Utilities should expand on the experience from the first two auction pilots with another auction in 2017 for 2018 delivery. The Utilities are directed to establish a working group to develop a 2018 DRAM pilot #3 proposal to be filed no later than September 1, 2016. The proposal should recommend a reasonable next step for the pilot, based upon the first two pilots. A budget of $27 million, double the current

[35] The monthly Aliso Canyon report was established in the March 23, 2016 Ruling and modified in the April 13, 2016 Email Ruling,

[36] D.14-05-025 at 4.

budget, is authorized for this pilot in the following breakdown for the utilities: $3 million for SDG&E and $12 million each for PG&E and SCE.

- SCE shall continue its Aggregator Managed Portfolio program contracts in 2017 as currently negotiated.
- PG&E shall not resume BIP marketing, as initially proposed.
- SDG&E shall clarify its BIP tariff language to require a re-test if the customer seeks a new firm service level.
- SCE shall not eliminate BIP account aggregation in 2017, but shall collect cost data to see whether elimination should occur in 2018.
- PG&E, SDG&E, and SCE, in implementing changes for integrating CBP in 2017, shall allow parties to break a resource into sub-10 MW resources and allow performance to be measured across all for the capacity available by each utility in the sub-LAP.
- PG&E is authorized to raise the incentives for the CBP, as proposed. While an increase in incentives should be based on the value of the capacity not inflation, it is also important to consider the value of retaining the overall load impact of the portfolio and encourage customers to transfer from the terminated AMP program to CBP.
- PG&E is authorized to revise is notification time for the CBP to "as soon as reasonably possible upon receipt of the CAISO market award by PG&E, but no later than 4 pm the day prior to the dispatch."
- SDG&E's Armed Forces Pilot is denied. SDG&E is encouraged to design a pilot for the Armed Forces focusing on the use of automatic demand response technologies.
- PG&E, SDG&E, and SCE shall implement ADR programs with the following uniform parameters: offer an incentive of $200 per kW of verified dispatchable load reduction not to exceed 75 percent of the total project costs with 60 percent of the incentives paid after installation, load

> shed test and enrollment in a qualified program and 40 percent paid after one year. Lastly, we confirm that reliability programs are not eligible for ADR due to the rare nature of dispatches. By adopting these uniform parameters, we create consistency among the Utilities, provide reasonable incentives to customers but ensure they are motivated to perform, and we provide fairness to ratepayers.

PG&E is authorized a budget of $ 59.9 million, SCE is authorized a budget of $ 56.28 million, and SDG&E is authorized a budget of $ 23.8 million. The specifics of the modifications are described below for each of the Utilities.

We take this opportunity to recognize the efforts of the Utilities to move toward bifurcation and CAISO market integration in 2017, as directed in the Guidance Ruling. However, we underscore two related policy issues that need clarification in this decision: 1) the proposed elimination of the two percent cap on reliability programs and 2) partial integration.

First, SCE proposes eliminating the two percent cap on reliability programs adopted in D.10-06-034.[37] In the September Guidance Ruling, parties were instructed that "any demand response program improvement proposal resulting in material facts in dispute and thus requiring evidentiary hearings will not be considered."[38] We consider the two percent reliability program cap to be an issue that could result in material facts in dispute and, therefore, may require an evidentiary hearing. Hence, the request to eliminate the 2 percent cap on reliability programs will not be approved in terms of 2017 bridge funding.

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[37] SCE Proposal at A-6.

[38] September Guidance Ruling at 5.

Second, SCE stated that it considered programs that are partially integrated into the CAISO market to be fully integrated for the purposes of dispatch.[39] We reiterate that the Commission's intent is to fully integrate supply side programs. We recognize the technical difficulties encountered in integrating these resources. However, given the nascent nature of integration, we are unwilling to consider a program fully integrated—when it is not—until we have taken into account all options. Hence, at this time, no program will be considered fully integrated until all delivered megawatts are able to be integrated and the associated customer registered into the CAISO market. Only those megawatts would provide resource adequacy value.

In comments to the proposed decision, the demand response utilities question how to manage demand response customers that cannot be integrated into a proxy demand response resource or a reliability demand response resource. PG&E in particular proposes the option of "islanding" customers from different demand response programs into a single proxy demand response resource to the extent feasible. The Commission continues to encourage the utilities to work with stakeholders to develop solutions to this and other technical barriers to CAISO integration. However, comments to the 2017 bridge funding proposed decision is not the proper procedural platform for presenting new solutions. We invite parties to present the proposed solutions to CAISO integration problems in the record development for future demand response program years, i.e. 2018 and beyond.

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[39] SCE Proposal at 5.

6.2.1. Overarching 2017 Demand Response Activities

There are six issues that apply to all three utilities and are addressed here: the termination of DBP, the continuation of the DRAM pilot, the uniform parameters for the ADR programs, the concern regarding the duplication of efforts in the pilots to address over generation, the continuation of funding for demand response studies, and the consolidation of future demand response activities and funding.

Demand Bidding Program

We first address the DBP. As described below, we grant the proposal of PG&E and SDG&E to terminate the DBP beginning in 2017 due to DBP's low performance and its high level of difficulty and expense to integrate the program into the CAISO market. We also allow SCE, as we discussed above, to continue its DBP through 2017 to help alleviate the effects of the Aliso Canyon gas leakage. The DBP termination for PG&E and SDG&E service territories is supported by all parties except for CLECA, who requests to continue the program in 2017 until an alternative can be developed and adopted. However, parties point out that the costs to keep DBP vastly outweigh any benefit of DBP.[40]

Historical program load impacts indicate that DBP has never achieved a strong showing of performance due to its current design. For example, PG&E states that DBP provides few incremental megawatts to PG&E's portfolio and, because DBP allows customers to opt-out of events, the quality of the load reduction is low and the cost-benefit ratio is poor.[41] While SCE has revised its

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40 *See* ORA Comments at 18.

41 PG&E Proposal at 27.

request and asks to continue DBP through 2017, SCE states that the average DBP event provided a load impact of 86 MW, most of which is delivered by customers who dually participated in DBP and BIP.[42] SCE notes that dual-participation further degrades the resource adequacy value of DBP because most of the MW are counted under BIP, e.g., in August 2016, DBP provided only 4.6 MW of resource adequacy.[43]

CLECA supports the continuation of DBP, and contends DBP is the only energy-based program that customers participating in the capacity-based BIP program can use for dual-participation.[44] However, the Joint Demand Response Parties underscore that dual participation is not permitted if a customer is participating in the wholesale market; thereby decreasing the importance of retaining the DBP.[45] Given the Commission policy of pursuing demand response supply resources that can be integrated into the CAISO market and the fact that the CAISO does not permit dual participation, we conclude that maintaining DBP for dual participation purposes is not a sufficient reason to continue the program.

Furthermore, all three Utilities claim that DBP does not meet the requirements necessary to be considered a demand response supply resource. For example, PG&E states that DBP is not compatible with the CAISO's Proxy Demand Response resource because the timing for event notifications and

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[42] SCE Proposal at 8.

[43] *Ibid*.

[44] CLECA at 2-3.

[45] Joint Demand Response Comments at 9.

subsequent responses do not adhere to day-ahead market timelines.[46] SCE and PG&E argue that significant changes leading to a substantially different program are necessary for DBP to be integrated into the CAISO market.[47] SCE also maintains that integration of DBP would require additional changes to BIP at an estimated cost of $640,000, further increasing costs.[48]

Given the significant and costly changes required to maintain DBP, in addition to the minimal load reduction achieved by the program, we find it reasonable to authorize the elimination of DBP for PG&E and SDG&E beginning in 2017 and for SCE beginning in 2018.

Demand Response Auction Mechanism Pilot

Next we address the DRAM pilot. In D.14-12-025, the Commission authorized a DRAM pilot for 2016 and 2017. The purpose of the pilot is to investigate whether a competitive procurement mechanism for supply side resources outside of traditional utility programs is viable; the pilot also is designed to provide experience in the CAISO market. The process is one in which the auction occurs a year prior to the required delivery by the customers. Hence the costs to perform the auction are incurred during one year while the delivery and the capacity payments for the performance are incurred the following year.

This decision addresses 2017 bridge funding for demand response programs. Later this year, the Commission anticipates issuing a decision in this

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[46] PG&E Proposal at 14-15. *See* also SDG&E Proposal at 54 contending DBP does not meet the requirements for supply side demand response as defined by the CAISO.

[47] PG&E Proposal at 15 and SDG&E Proposal at 8.

[48] SCE Proposal at 8.

proceeding that will provide guidance to the utilities for their demand response program year 2018 and beyond applications. At this time, we cannot determine whether a DRAM will be adopted by the Commission for 2018 and beyond programs. However, given the apparent success of the 2016 auction process and the anticipated potential for the 2017 auction process, we find that it is reasonable and prudent to continue, at the very least, the current form of the DRAM as a pilot.

PG&E, SCE, and SDG&E all argue that the DRAM cannot be considered a success until the results of the performance of the winning bidders is known. However, we highlight several descriptions of the auctions, as offered by parties. PG&E notes robust responses in both the 2016 and 2017 requests for offers, as well as a growth in the number of bids and bidding parties participating in the 2017 versus the 2016 requests for offers.[49] SCE states that the DRAM has been successful in attracting third-party interest and has generated higher megawatt volume of offers and contracts than expected.[50]

Hence, we re-establish the DRAM working group to jointly develop a proposal for the parameters of a third pilot to be held in 2017 with delivery in 2018. The minimal requirements shall begin at the current auction level. Similar to prior Commission directives, the Utilities shall sponsor the working group meetings but all parties are encouraged to participate. At least one staff member of the Energy Division shall attend. Because it is probable that one or more Commissioners or Commissioner advisors may attend one or more meetings, Energy Division staff shall work with the Utilities to notice the working group

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[49] PG&E Opening Comments at 5.

meetings on the Commission's Daily Calendar. The first meeting of the working group shall occur no later than 14 days following the adoption of this decision. We encourage the Utilities to work with the parties and other stakeholders to develop as much consensus as is possible. We recognize that complete consensus may not be possible. The three Utilities shall file, no later than September 1, 2016, a tier three advice letter requesting adoption of a proposal for a third demand response auction mechanism pilot.

As previously indicated, the Utilities are authorized a budget of $27 million, double the current budget, for the continuation of this pilot in the following breakdown for the utilities: $3 million for SDG&E and $12 million each for PG&E and SCE. We clarify that these funds are available beginning in 2016 to ensure that the 2017 auction will take place in time for 2018 delivery.

ORA and SCE caution the Commission to adopt some parameters around this increased budget. ORA suggests that the utilities use discretion to accept and approve bids. ORA explains that in prior auctions, the utilities were directed to procure bids up to the CAISO customer registration limits or the authorized budgets. ORA contends that this third pilot presents an opportunity to accept and approve bids in a prudent and sensible manner to best fit utility portfolio needs.[51] SCE agrees with ORA adding that requiring the procurement up to the budget or registration cap could result in funding uncompetitive bids.[52] We agree that with the third auction pilot, it is important for the Utilities to be prudent and sensible in selecting and approving bids. Hence, the Utilities are

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[50] SCE Reply Comments at 2.

[51] ORA Comments to the Proposed Decision, May 23, 2016 at 2.

[52] SCE Reply Comments to the Proposed Decision, May 31, 2016 at 2.

instructed to ensure that the bids fit portfolio needs and offer the best value to the ratepayers.

Automated Demand Response Program

Next, we address the ADR program. Over the course of the past five years, the Commission has expressed a desire to adopt a statewide ADR program with common program rules and incentive levels. In D.12-04-045, the Commission directed the Utilities to collaborate on the development of a statewide ADR program with common program rules and incentive levels. The Utilities filed advice letters on October 31, 2013 proposing a joint statewide ADR design. ORA protested the advice letter stating that the advice letter did not comply with D.12-04-045. Furthermore, ORA contended that the Commission should develop the statewide program within R.13-09-011. The Commission sent the three Utilities a disposition letter on July 7, 2014 referencing ORA's protest and noting that 2015-2016 demand response bridge funding declined to adopt a statewide program due to the narrow nature of the decision.

In the September Guidance Ruling, the Utilities were specifically directed to address improvements in the ADR, Technology Incentives/Technical Assistance Programs. While certain incentives and program rules remain inconsistent, the ADR program proposals are similar across the three Utilities. We note that due to the similarities between the three utility programs, we determine it is reasonable to adopt a statewide ADR program with the following uniform parameters for PG&E, SDG&E, and SCE to implement: each Utility shall offer an incentive of $200 per kW of verified dispatchable load reduction not to exceed 75 percent of the total project costs with 60 percent of the incentives paid after installation, load shed test and enrollment in a qualified program and 40percent paid after one year. Furthermore, we eliminate BIP as one of the

ADR-eligible programs. Given the infrequent dispatch of BIP, we do not consider the Commission's investment in ADR devices recoverable through a reliability program. As further described below, this set of uniform parameters creates consistency among the Utilities, provides reasonable incentives to customers but ensures that the customers are contributing, and provides equity to ratepayers.

These parameters do not apply to the SCE ADR Express program, which provides incentives to customers with peak electricity demand of 50-499 (kilowatts) kWs for predetermined savings on standard lighting and HVAC technologies or to the PG&E Small and Medium-sized Business ADR program, which offers a streamlined approach to this class of customers; we find the parameters as proposed by PG&E and SCE to be acceptable for this particular set of customers.

As indicated in the table (Table 2) below, each Utility proposes a similar set of parameters for the ADR program:

Table 2
ADR Program Parameter Proposals

Utility	Incentive	Cap	Incentive Split
PG&E	150/kW	50 percent of Project Cost	100 percent following installation
SDG&E	300/kW	50 percent of Project Cost	100 percent up front
SCE ADR Customized	150 /kW	50 percent	100 percent up front

Each of the Utilities propose moving from the current 60-40 split of the incentive to paying 100 percent incentive after installation of the technology. PG&E maintains that eliminating the split incentive should address customer concerns of not being paid in full for their investment.[53] SCE asserts that the 60-40 split only incents performance through the first year.[54] No party opposes this change; however, the Joint Demand Response Parties argue that SCE had a successful ADR program utilizing the 60-40 split with a $300/kW incentive.[55] We are not convinced by the Utilities' claims that providing 100 percent up front will improve the program. The Commission previously denied a request to provide customers 100 percent upon project completion, finding that a one-year investment is a reasonable minor inconvenience in comparison with the improved cost-effectiveness.[56] Hence, we find it reasonable to maintain the 60-40 incentive split.

In comment to the proposed decision, the three Utilities and the Joint Demand Response Utilities oppose the 60-40 split. PG&E states that historical enrollment data demonstrates the negative impact of the 60/40 split. PG&E provides a chart indicating decreases in enrollment.[57] However, the decreases in new enrollments shown in this table date back to 2011 where new enrollments decreased from 45 in 2010 to 21 in 2011, before the 60/40 split was adopted. The decreases in enrollment cannot be linked to the 60/40 split without further study and data.

The Utilities offer differing proposals for incentives, ranging from $150 to $300/kW. PG&E and SCE reason that a reduced incentive structure will better

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[53] PG&E Proposal at 44.

[54] SCE Proposal at 20.

[55] Joint Demand Response Parties Comments at 14.

[56] D.12-04-045 at 142.

[57] PG&E Opening Comments at 11.

incent program performance throughout the three-year program enrollment obligation, as customers will have to perform to recoup their investment.[58] SCE states that the average incentive cost per kW for ADR has been $244/kW.[59] Joint Demand Response Parties claim that the reduced incentive levels will extend investment payback periods to 4 – 5 years and, furthermore, the reduced levels conflict the Commission's objective of encouraging changes in the use of demand response to better act as resource in the CAISO market and provide needed flexibility for integrating increasing renewable resources.[60] The Guidance Ruling stated that ADR programs and technologies are key factors in advancing demand response. Hence, the Commission must find a balance between providing incentive levels that increase participation while ensuring cost-effectiveness. We find that an incentive level of $200/kW is reasonable for incenting participation and maintaining cost-effectiveness.

The Utilities propose capping the incentives paid at 50 percent of the total cost of the technology installation. PG&E contends this will increase cost-effectiveness of ADR by aligning with the PG&E energy efficiency programs.[61] PG&E also states that the lower cap will prompt customers to enroll in, and stay on, a demand response program to make the most of their investment.[62] SCE contends the reduced incentive will continue to retain interest in ADR technology and better reflect market pricing conditions. Joint Demand

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[58] SCE Proposal at 20 and PG&E Proposal at 44.

[59] SCE Proposal at 20.

[60] Joint Demand Response Parties Comments at 14.

[61] PG&E Proposal at 44.

[62] *Ibid*.

Response Parties argue that the proposal appears to be arbitrary and not based on any studies or process evaluation.[63] Again, the Commission must maintain a balance between providing incentive levels that increase participation but ensuring cost-effectiveness. We find that a 75 percent cap is reasonable in ensuring cost-effectiveness of the program while providing incentive levels that lead to increased participation. The Utilities are directed to implement the previously described uniform parameters for the 2017 ADR program.

Lastly, PG&E requests that the Commission make BIP a qualified program for ADR.[64] Currently SDG&E's ADR program includes BIP as an eligible program for ADR devices. TURN opposed this request noting the infrequency of dispatches for BIP. TURN contends that it is not appropriate for ratepayers to fund the installation of technology designed to facilitate rapid automatic response of lighting, HVAC or other end-uses in response to an internet communications signal for a program that is dispatched only infrequently due to abnormal emergency conditions.[65] TURN stated that BIP was dispatched a total of three times during 2014-2015. In the Guidance Ruling, the utilities were directed to address improvements in the ADR. We do not see how providing ADR devices to customers who, in turn, only use the devices three times in two years is an improvement. PG&E's request is denied. Furthermore, in keeping with our theme of uniformity, we clarify that all reliability programs are ineligible for the ADR program beginning in 2017.

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[63] Joint Demand Response Parties Comments at 20.

[64] PG&E Proposal at 44.

[65] TURN Comments at 5.

Over Generation Pilots Relationship with Storage Proceeding

We now turn to the overarching issue of a concern that the Utilities' over generation pilots raise issues of double compensation and submetering that are being addressed in the storage rulemaking. In the Guidance Ruling, the Utilities were encouraged to propose pilots to address over generation resulting from renewable energy. Referencing a 2014, Energy+Environmental Economics (E3) report on the effect of increased renewables over time, the Guidance Ruling directed the Utilities to propose pilots that addressed one of five mitigation areas.[66] Furthermore, the Utilities were cautioned not to duplicate the efforts of PG&E's excess supply pilot. PG&E, SDG&E and SCE each propose a pilot to address over generation. CLECA contends these pilots should not be approved until overlapping policy issues are resolved in the storage rulemaking. The Utilities proposed the following over generation pilots:

- PG&E proposes to continue its excess supply pilot in order to meet the directive of the Guidance Ruling. The purpose of the original excess supply pilot was to explore how customers could mitigate over generation by shifting load consumption to realign supply and demand. PG&E explains that, in 2017, the pilot would further test the goals laid out in the initial steps, ensure that customer actions taken to realign supply and demand during excess supply situations at the system level do not create congestion on the distribution wires; experiment with financial incentives; and explore appropriate baseline methodologies.

[66] The mitigation areas are conventional demand response; advanced demand response; greater coordination statewide among parties which use and generate energy to create more balance; energy storage; and a 50 percent renewable portfolio standard (RPS) standard with more diverse energy in the portfolio.

- SCE proposes a pilot to study the application of pumped water storage. Working with four water companies, the pilot will pump water to elevated tanks in response to an over generation demand response signal. SCE anticipates researching energy storage system performance; beneficial use cases for absorbing excess energy during an over-generation event; customer behavior and drivers needed; multi-use energy storage systems that use automation; ancillary services to test signal response and validate integration of the over generation pilot resources into the market; and determination of temporal and locational value of load shifting.
- SDG&E explains that the purpose of SD&E's over generation pilot is to determine whether storage can be used to address excessive export of distributed solar to the grid during non-peak periods and the lack of flexible generation during demand response events.

CLECA contends that each of these pilots includes the use of storage. But with several open policy issues regarding using storage for demand charge management, CLECA recommends that the Commission deny the pilot until those policy issues are settled in R.15-03-011.[67]

We agree that there are several unanswered policy questions regarding the use of storage. However, the three utilities state no intention to directly address these overarching issues. While, CLECA contends that SDG&E "acknowledges the issue of differentiating demand response from normal storage discharge in response to time of use rates,[68] SDG&E addresses this issue in terms of the cost-effectiveness discussion and market benefits and costs. Hence, we find that SDG&E has no intention of addressing the open policy issues that CLECA

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[67] CLECA Comments at 14-15.

[68] CLECA Comments at 6 referencing SDG&E Proposal at 82.

references. We find that the information gathered from the three over generation pilots can be useful to the demand response rulemaking as well as the storage rulemaking. We, therefore, find the three pilots reasonable to implement.

Continued Funding for Demand Response Studies

We find it reasonable to continue to provide funding for the study of demand response in California. We authorize the following budgets: $400,000 each for PG&E and SCE, and $200,000 for SDG&E.

The Guidance Ruling instructed the Utilities to comment on whether the Commission should continue to include funding for studies to advance the Commission's demand response objectives. PG&E recommends that the Commission continue to authorize a $1 million study fund to promote demand response, contending that follow up work on the Demand Response Potential Study needs to be performed and this is the venue. PG&E adds that unused funds not spent by June 2019 should be returned to ratepayers. SDG&E and SCE agree that the Commission should continue to fund studies to advance demand response. However, SDG&E supports the opportunity of the Utilities and other stakeholders to participate in the evaluation process to ensure studies are accurate. No party opposes the continued funding of demand response studies. We find it reasonable to continue to fund demand response studies at a budget of $1 million to be shared by the Utilities as indicated above.

Additionally, PG&E requests approval of $600,000 for PG&E to perform its own demand response research on such topics as demand response forecasting. This request does not comply with the guidance given to the Utilities in the Guidance Ruling. Furthermore, PG&E did not provide adequate detail on the proposed study. We deny the $600,000 research funding request by PG&E.

Demand Response Activities and Funding Consolidation

Our final overarching issue is the issue of consolidating requests and funding for all demand response activities. As further discussed below, we direct the Utilities to include all demand response funding requests including incentives in future demand response application processes, the next being for 2018 and beyond.

In the 2017 Guidance Ruling, the Utilities were directed to include in their 2017 proposals, a schedule to consolidate all demand response programs and incentives into one demand response portfolio. The Guidance Ruling explained that D.12-4-024 indicated that demand response applications have not always included all demand response related programs and incentives. Hence, the Guidance Ruling also directed the Utilities to identify all programs and incentives provided through demand response but established external to the 2012-2014 demand response application proceeding (Application 11-03-001 et al.), not including dynamic pricing programs (e.g., Critical Peak Pricing, Real-Time Pricing, and Time-of-Use rates)[69] Each of the Utilities complied with the request to include a list of programs and incentives established external to the 2012-2014 application process. In response to a consolidation schedule, each of the Utilities provides a different perspective.

PG&E plans to consolidate all demand response program funding requests within the demand response application process beginning in 2018. SCE and SDG&E propose to omit certain programs from the application process and include them in general rate case proceedings, but provide no justification to

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[69] Pursuant to D.12-04-045, dynamic pricing programs should not be included in the demand response program applications.

keep their funding requests separate from funding requests for the other demand response programs. However, in response to the March 16, 2016 Ruling requesting additional information and clarification on the Utilities' proposals, SCE revises it earlier proposal and states that it proposes to consolidate its demand response budgets, including program costs and incentives, into the next demand response funding application.

Additionally, SDG&E proposes that all load modifying demand response programs, including Peak Time Rebate, should be integrated into the general rate case proceedings. We recognize that Peak Time Rebate is a load modifying resource like Critical Peak Pricing and Real-Time Pricing. However, we note that Critical Peak Pricing, Real-Time Pricing and Time of Use are rate programs, whereas Peak Time Rebate is a tariffed program whose customers receive incentives for a particular action. We find that funding for the Peak Time Rebate program is more appropriately requested in a demand response program application process.

Furthermore, SDG&E argues that certain demand response programs belong in a general rate case proceeding because it is "consistent with current treatment."[70] This is not a reasonable justification. Consistency, by itself, is not necessary a correct approach. SDG&E provides no evidence of any barriers to consolidating the funding requests.

We find that all three Utilities are capable of consolidating all demand response program activities, including incentives, into the demand response application process. PG&E, SDG&E, and SCE are directed to request funding for

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70 SDG&E Proposal at 66.

all demand response programs and incentives through the demand response applications process beginning with the upcoming application for program years 2018 and beyond

6.2.2. PG&E 2017 Demand Response Program Activities and Budgets

We find that PG&E's proposal is in compliance with both D.14-12-024 and the Guidance Ruling in that it indicates a concerted effort of moving the demand response programs closer to bifurcation and CAISO market integration. PG&E's proposal includes each of the elements requested in the Guidance Ruling. In regards to the reasonableness of the PG&E proposal for activities and budgets, we must balance the Commission desire to increase market integration with ratepayer fairness and competitive neutrality, as well as ensuring customers are properly awarded for program participation. Hence we approve most of PG&E's proposal, but deny or modify the proposal as discussed below.

- PG&E shall not resume BIP marketing, as initially proposed.
- PG&E is authorized to revise its notification time for the CBP to "as soon as reasonably possible upon receipt of the CAISO market award by PG&E, but no later than 4 pm the day prior to the dispatch."
- PG&E request to raise the incentives for the CBP is approved. While increases in incentives should be based on the value of the capacity not on inflation, we also must consider the value of the load impact of customers transferring from the AMP program to the CBP.
- PG&E shall modify its CBP event trigger to include a price component in conjunction with the 15,000 Btu/kWh so that the program can be priced appropriately for the market, as proposed by SCE. However, we address this issue in our discussion of SCE's proposal.

- In implementing changes for CBP in 2017, PG&E shall also allow parties to break a resource into sub-10 MW resources and allow performance to be measured across all for the capacity available by each utility in the sub-LAP.
- PG&E shall adhere to the milestones and deadlines it proposes for CAISO market integration.

Base Interruptible Program (BIP)

PG&E plans to complete the required integration of BIP into the CAISO RDRR market no later than May 1, 2017. PG&E also requests to resume marketing the program in 2017, subject to the megawatt cap approved in D.10-06-034 and after integration into the CAISO market.[71] PG&E notes that the Commission discontinued the marketing of BIP in D.12-04-045. However, PG&E claims the program is under the cap for reliability demand response, as established in D.10-06-034, and has room to grow.[72] The request to resume BIP marketing is opposed by CLECA and the Joint Demand Response Parties, who express concern about the cap. In responses to party comments, PG&E withdraws its request to resume marketing, but notes that it may reiterate this request in its 2018 demand response application. We allow the withdrawal of the request.

Capacity Bidding Program (CBP)

PG&E proposes two changes to its CBP program: 1) adjusting the day-ahead notification time to 4 pm and 2) increasing incentives by 4.5 percent to account for inflation. The Joint Demand Response Parties recommend three

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[71] PG&E Proposal at 4. D.10-06-034 adopted, as part of the Settlement Agreement, the condition that the amount of emergency-triggered demand response megawatts attributable to resource adequacy is set at 2 percent of system peak, beginning in 2014.

[72] *Id*. at 28.

changes: 1) improvements to the dispatch trigger; 2) modifications to the payment bands and penalties; and 3) inclusion of residential participants. Additionally, the Joint Demand Response Parties request the Commission to order the Utilities to allow parties to break a resource into sub-10 MW resources and allow performance to be measured across all for the capacity available by each utility in the sub-LAP. PG&E confirmed this is already the case.[73]

As discussed in detail below, we adopt the notification time with specific language as requested by the Joint Demand Response Parties. However, we grant the request to adopt a 4.5 percent increase in incentives. While we recognize that inflation should not be the reason to increase incentives, we also must consider the value of the load impact of customers transferring from AMP to CBP. We grant the requested dispatch trigger, but discuss the issue in our discussion on SCE's proposal. We deny the payment bands and penalties revisions requested by the Joint Demand Response Parties; as described below, the CBP program cannot be compared to the DRAM pilot. We also adopt the request by the Joint Demand Response Parties to allow customers to break a resource into sub-10 MW resources and allow performance to be measured across all for the capacity available by each utility in the sub-LAP. We find that CBP residential participation should not be addressed in a one-year bridge funding decision and, as such, deny the request to expand participation to residential customers. However, we will address this issue in an upcoming Ruling regarding the 2018 and beyond demand response application.

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[73] PG&E Reply at 2 confirmed that, consistent with CAISO requirements, "PG&E will be avoiding the need for telemetry or a waiver by splitting up resources such that each PDR for CBP remains below 10 MW."

We first address the requested time notification change. PG&E explains that adjusting the day-ahead notification time from 3:00 p.m. to 4:00 p.m. to account for instances when the day-ahead market closes later in the day will provide resources that receive market awards sufficient time to be dispatched.[74] Joint Demand Response Parties cautioned that this may prove to be problematic for participants without ADR and requested revisions to state that the "notifications shall be sent as soon as reasonably possible upon receipt by PG&E, but no later than 4 pm the day prior to the dispatch."[75] In reply comments, PG&E agreed to this language.[76] We find the language reasonable and adopt it.

Next, we address PG&E's request to increase CBP capacity incentives. PG&E states that the CBP capacity prices were last updated in 2012 and proposes to increase them by 4.5 percent to account for inflation.[77] This is supported by CLECA, who states that increasing the incentives makes CBP a more desirable alternative for those customers transitioning from the AMP program.[78] However, ORA argues that inflation should not be a basis for determining CBP incentives, and notes that the increased incentive decreases the cost-benefit ratio of two of CBP's cost-effectiveness tests, the Participant Cost Test (PAC) and the Ratepayer Impact Measure (RIM) tests.[79]

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[74] PG&E Proposal at 28.

[75] Joint Demand Response Parties Comments at 10-11.

[76] PG&E Reply at 3.

[77] PG&E Proposal at 28.

[78] CLECA Comments at 9

[79] ORA Comments at 11-12.

In reviewing the cost-effectiveness results, we underscore that past Commission practice has been to focus on the TRC results. PG&E claims that the TRC result for both the day-ahead and the day-of CBP is a 1.0.[80] While we agree that inflation should not be the reason to increase incentives, we must consider the claim by the Joint Demand Response Parties that the increase is not "significant enough to incent participants to move to CBP from the soon-to-be defunct AMP."[81] We agree with CLECA that CBP *with an increased incentive* may be more desirable to those customers transitioning from AMP. Not approving the proposed increase could lead to a loss of load impact from these customers deciding not to enroll in the CBP. Given that the CBP, with the increased incentives, remains cost-effective and given the desire by the Commission to maintain the current level of load impacts, we find it reasonable to grant PG&E's request to increase the CBP incentive by 4.5 percent.

Lastly, we address the Joint Demand Response Parties recommendations that the Commission require the Utilities to adopt modifications to the payment bands and penalties for the CBP. We deny the request of the Joint Demand Response Parties. The proposal to adopt energy imbalance charges, in lieu of capacity de-rates, does not appropriately consider the risks imposed upon the Utilities. The Joint Demand Response Parties argue that the payment bands currently imposed in the CBP are punitive and inconsistent with penalty assessments in the wholesale market. Requesting that capacity payment be more consistent with performance, the Joint Demand Response Parties contend that charging third parties a capacity de-rate does not accurately reflect the level of

[80] *Id*. at 39.

cost incurred by the utility in bidding the resource into the wholesale market and the resources' failure to match the dispatch instructions of the CAISO.[82]

The Joint Demand Response Parties argue that by using the capacity de-rates, the Utilities are treating each individual aggregator as if its performance alone will cause the utility to incur costs when the utility is bidding a combined resource into the wholesale market.[83] SCE disputes this claim, arguing that CBP (and AMP) should not be compared with DRAM for several reasons. First, SCE contends that aggregators do not bear the risks in CBP and AMP because SCE is the demand response provider and the Scheduling Coordinator.[84] Second, SCE argues that in CBP and AMP, a customer under-performance could cause the utility to receive a lower capacity value for the program in following years, while future payments to the aggregator may not be affected.[85] Finally, the capacity payment structure in CBP is designed to reflect energy and capacity value, whereas energy imbalance charges represent only a portion of aggregator under-performance impact.[86] PG&E supports SCE in maintaining the current payment structure.[87]

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[81] Joint Demand Response Parties Comments at 9.

[82] Joint Demand Response Parties Comments at 4.

[83] *Ibid*.

[84] SCE Response at 4.

[85] *Ibid*.

[86] *Ibid*.

[87] PG&E Response at 3-4.

We agree that that the penalty structures for CBP should be different from the DRAM. The auction mechanism is a pilot and remains under development; as such, its future penalty structure has yet to be determined and could change. Furthermore, the risks for the Utilities are greater in CBP and AMP then in the auction pilot. The current CBP payment/penalty structure provides for those risks. Hence, we find it reasonable to continue using the current CBP payment/penalty structure.

CAISO Integration Budget

PG&E requests a budget of $12 million between 2016 and 2017 to implement IT system development and changes to enable integration of PG&E's programs into the CAISO market. Joint Demand Response Parties oppose the budget amount, stating it is too high, but did not provide any indication of what an appropriate amount would be. The Joint Demand Response Parties maintain that the proposed budget amount for CAISO integration is much greater than that spent to facilitate efforts to facilitate third party integration. Joint Demand Response Parties contend that this disparity leads to competitive inequity: 1) PG&E demand response programs will be ready to integrate in the CAISO market, while PG&E may not have adequate capability to enable third-party demand response direct participation in the CAISO market, and 2) PG&E receives integration funding from ratepayers while third-party providers have to recover these costs from market proceeds and customers.[88] No other party opposes the budget amount.

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[88] Joint Demand Response Parties Comments at 6.

In comments, PG&E disputes the Joint Demand Response Parties' contention of competitive inequity. PG&E explains that the requested 2017 integration budget "reflects the cost of integrating an existing portfolio of demand response programs, including those available to third-party aggregators.[89] PG&E reasons that the processes for third party demand response direct participation are in the initial implementation stage and thus, require further Commission review to determine whether additional costs are reasonable.[90]

Throughout the life of this proceeding, the Commission has reiterated its commitment to increasing the amount of demand response supply resources and increasing the amount of the supply resources integrated into the CAISO market. These resources are provided by utility programs and third party demand response provider programs. Thus it is important to ensure adequate funding such that the existing portfolio is able to be integrated into the market. Furthermore because direct participation is in the initial implementation step, it is not possible to compare the costs of direct participation with utility demand response programs, at this time. We find PG&E's request for CAISO market implementation funding to be reasonable and adopt PG&E's budget of $6.2 million as recommended. PG&E shall adhere to the milestones and deadlines it proposed in Table 1 of its March 24, 2016 comments, including:

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[89] PG&E Comments at 2.

[90] *Ibid.*

- Completion of Customer Management System in the fourth quarter of 2016;
- Completion of Control Center Application and Process Orchestration Systems in the first quarter of 2017 for BIP, and the third quarter of 2017 for CBP and SmartAC;
- Finish registering BIP resources as RDRR no later than May 1, 2017; and
- Finish registering CBP and SmartAC no later than January 1, 2018.

Any deviations from these milestones or schedule should be brought to the Commission's attention through a notice to the R.13-09-011 service list, or its successor service list.

6.2.3. SDG&E 2017 Demand Response Program Activities and Budgets

We find that SDG&E's proposal is in compliance with both D.14-12-024 and the Guidance Ruling in that it indicates a concerted effort of moving the demand response programs closer to bifurcation and CAISO market integration.[91] SDG&E's proposal included all of the elements requested in the Guidance Ruling. In regards to the reasonableness of the SDG&E proposal for activities and budgets, we again must balance the Commission desire to increase market integration with ratepayer fairness and competitive neutrality, as well as ensuring customers are properly awarded for program participation. While, we approve most of SDG&E's proposal, we deny or modify the following issues as further discussed below;

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- SDG&E shall modify its CBP event trigger to include a price component in conjunction with the 15,000 Btu/kWh so that the program can be priced appropriately for the market, as proposed by SCE. However, we address this issue in our discussion of SCE's proposal.
- SDG&E shall clarify its BIP tariff language to require a re-test if the customer seeks a new firm service level.
- The request by SDG&E to perform an Armed Forces Pilot is denied. SDG&E is encouraged to design a pilot for 2018 that focuses on automatic demand response for the Navy. We also address the claim by TURN that the Summer Saver pilot is duplicative.

Base Interruptible Program (BIP)

As previously discussed above, SDG&E proposes several changes to the BIP in order to integrate the program into the CAISO RDRR. The parties support the majority of the requested changes. While TURN supports all the changes as well, it points out the need for a clarification regarding a proposed change in language defining the Firm Service Level. TURN contends that the proposed change appears to give a customer the option to provide a firm service level with no additional conditions. TURN recommends that the language be clarified such that it requires a re-test if the customer asks for a new firm service level. TURN notes that this is similar to the requirement for a new firm service level elsewhere in the tariff. SDG&E did not provide a response in reply comments. We find SDG&E's request reasonable as it ensures consistency in the tariff and increased reliability from the customer. We require SDG&E to re-test if the customer asks for a new firm service level.

SDG&E Summer Saver and Armed Forces Pilots

We find SDG&E's Summer Saver programmable communicating thermostat pilots to be compliant with the expectations of the Commission and, therefore, reasonable to adopt. In addition to the previously discussed over generation pilot, SDG&E requested funding for a Summer Saver program programmable communicating thermostat pilot and a pilot to replace DBP for the Navy. We discuss these two pilots in depth below.

SDG&E contends that its Summer Saver pilot will provide direct access customers with newly installed programmable communicating thermostats and not participating in a demand response program, the opportunity to use the thermostats to participate in the Summer Saver program, which will be bid as a supply resource. The dual purposes of the pilot are to engage direct access customers in supply side demand response while piloting the strategy to transition from the current air conditioning switches to newer technology such as the thermostats. TURN argues that the pilot is duplicative of other pilots using this technology.[92] SDG&E contends that the purpose of the Summer Saver pilot is not to test the viability of the technology itself but rather test the viability of the technology for direct access customers thus expanding the choices for direct access customers.[93] We find that the Summer Saver is not duplicative of other programmable communicating thermostat pilots and therefore is reasonable is to approve.

Initially, the Armed Forces Pilot seems prudent considering the elimination of DBP and the Navy being the DBP's sole customer. However, as

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92 TURN Comments at 5.

93 SDG&E Response at 4.

discussed below, we deny this pilot, and approve a placeholder for a similar pilot based on CBP and Automatic Demand Response. Creating a BIP-like pilot program for the Navy and simultaneously using automated demand response devices is inefficient because reliability programs are not dispatched frequently and investing in these devices will not result in a positive return on investment.

SDG&E proposes to create the Armed Forces Pilot, which will test a modified program designed specifically for the Navy. The Navy is currently a customer of the DBP, which SDG&E has proposed to eliminate. While SDG&E does not specifically state in its proposal, its plan is to create a BIP-like pilot program for the Navy, which is a reliability program. In addition, SDG&E proposes to target 30 sites for automated demand response devices. The purpose of the pilot is to provide the Navy with the opportunity to participate in a supply side demand response program. SDG&E anticipates the results of this pilot could lead to pilots with other branches of the armed forces. SDG&E states that the pilot's success will be measured by how successfully the available resources can be integrated into supply side resources. SDG&E notes that many obstacles remain with working with the Navy on this project, including facility and technical challenges.[94]

No party opposes this pilot. However, we are concerned that the investment in automated demand response devices will not be recovered through a reliability program. First, this is a one-year pilot and in order to learn from the pilot, SDG&E must dispatch it multiple times. However, with the pilot essentially being a reliability program, we do not anticipate many dispatches.

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[94] SDG&E Proposal at 54-58.

Second, as noted by SDG&E, the Navy has identified over 300 sites where it is targeting the installation of automated demand response devices.[95] If the Commission subsidizes these devices through the ADR program, it would not recoup its investment through a reliability program. Hence we deny the Armed Forces Pilot, as proposed.

However, we recognize the interest of the Navy in participating in demand response programs and the potential demand response load impact it could provide. Hence, we adopt a placeholder for a pilot and direct SDG&E to work with the Navy to create a CBP-like pilot program that better utilizes automated demand response devices. SDG&E shall file a Tier 2 Advice Letter for the CBP-like pilot, no later than September 30, 2016. We authorize a budget cap of $250,000 for the pilot.

In comments to the proposed decision, SDG&E requests that the Commission allow the filing of the advice letter to be optional. SDG&E expresses concern that it may not be able to come to an agreement with the Navy on a new proposal.[96] We appreciate SDG&E's concern but find that the revisions we require should be amenable to the Navy. Hence, we maintain the requirement to file the Advice Letter, as discussed above.

6.2.4. SCE Demand Response Program Activities and Budgets

Following a March 24, 2016 filing pursuant to a March 16, 2016 Administrative Law Judge Ruling requesting additional information, we find that SCE's proposal is in compliance with both D.14-12-024 and the Guidance

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[95] SDG&E Proposal at 56.

[96] SDG&E Opening Comments, May 23, 2016 at 2-3.

Ruling in that it indicates a concerted effort of moving the demand response programs closer to bifurcation and CAISO market integration.[97] In regards to the reasonableness of the SCE proposal for activities and budgets, we note once again that we must balance the Commission desire to increase market integration with ratepayer fairness and competitive neutrality, as well as ensuring customers are properly awarded for program participation. While, we approve most of SCE's proposal, we deny or modify as discussed below:

- SCE is authorized to continue its AMP program contracts on a one-year basis, as currently negotiated;
- SCE shall not eliminate BIP account aggregation in 2017, but shall collect cost data to see whether elimination should occur in 2018; and
- SCE's proposal to add a price trigger to the heat rate trigger in CBP is approved. Additionally, we require SDG&E and PG&E to implement the price trigger.

We first address a request by ORA to deny SCE's one year continuation of the AMP contracts. SCE requests authorization to negotiate modified AMP contracts for 2017 and continue to integrate the resources into the CAISO wholesale market. ORA recommends that the Commission deny the request on the basis that the AMP program is ineffective and, instead, require SCE to transition these customers into the more effective CBP. SCE argues that it is premature to discontinue the AMP program when the Commission has not determined whether the DRAM is successful. SCE states that maintaining the AMP program encourages multiple entry points for demand response.

[97] The March 24, 2016 filing includes revised cost-effectiveness analyses using the correct model for the A Factor and a schedule for consolidating demand response budgets.

In an August 6, 2015 Joint Assigned Commissioner and Administrative Law Judge Ruling, parties were asked whether the Commission should authorize funding for the continuation of AMP contracts in 2017 or whether the Commission should require new and improved Requests for Proposals for these programs? In the Guidance Ruling, the Utilities were directed to "not include any requests to consider contracts beyond the 2017 program year. In order to reflect the potential for future change, the Utilities should include in their 2017 filing proposals that balance the desire by the Commission for improvements in 2017 but take into account that 2018 and beyond will most likely require even bigger changes."[98] We agree with ORA that the AMP program provides a lower number of dispatches in comparison with the CBP program.[99] However, as pointed out by SCE, AMP dispatch hours are based on CAISO awards and there is no evidence that the DRAM will result in increased dispatches as compared with AMP.[100]

We find that the continuation of SCE's AMP contracts is reasonable, but we reject SCE's proposal to renegotiate the contract. The guidance ruling states, "…revising the AMP contracts for a single year could be unreasonably disruptive, given that we anticipate great changes in requirements for the demand response portfolio beginning in 2018, including the potential dissolution of AMP contracts in favor of using the demand response auction." Thus, we

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98 Guidance Ruling at 11-12.

99 In comments, the Joint Demand Response Parties object to this statement calling it factually incorrect. However, according to the Demand Response Load Impact Reports from 2013 – 2015, PG&E called CBP 70 times from 2013 through 2015 and AMP was called only 58 times.

100 SCE Comments at 5.

authorize a one-year extension of the existing contracts, as currently written, for 2017, which preserves a full range of options for the Commission in 2018 and beyond.

BIP

SCE proposes two changes for BIP in 2017: 1) remove customers for repeated non-performance and 2) remove the option for aggregation of accounts on BIP. No party opposes removing customers for non-performance; hence we adopt this modification. While the elimination of the aggregation option is supported by CLECA,[101] the Joint Demand Response Parties contend that removing the option for aggregating BIP accounts limits customers' ability to participate in demand response. Furthermore, the Joint Demand Response Parties argue that this proposal fails to consider Public Utilities Code Section 740.7 requiring that the Commission's interruptible service programs shall allow customers to aggregate multiple accounts to meet any minimum kilowatt requirements for program participation.[102] Additionally, TURN recommends that the Commission require SCE to provide data concerning the alleged costs because the "aggregation option might become more useful once BIP is integrated into the CAISO market."[103]

In response, SCE argues that Public Utilities Code Section 740.7 provides the authority to determine other parameter before allowing customers to aggregate multiple accounts. SCE clarifies that it is asking he commission to determine that an appropriate parameter to consider is the costs to administer an

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101 CLECA at 4.

102 Joint Demand Response Parties Comments at 17.

103 TURN at 7-8.

unused option. We appreciate SCE looking for multiple ways to save costs. However, we agree with TURN that the record has no data on the alleged costs. Furthermore, the Commission should determine whether integrated BIP has more use for the aggregation option. We deny the request to eliminate the BIP aggregation option. However, we direct SCE to collect data on this for future review. We recognize, however, that the effect of integrating BIP into the CAISO market in 2017 will not be known in time for revisiting this issue in 2018.

CBP Heat Trigger

SCE proposes to modify the current CBP event trigger to ensure the product is priced properly for the relevant market. SCE explains that there are significant price differences between the day ahead and the real time markets. SCE recommends including a price component in conjunction with the 15,000 Btu/kWh heat rate so that the program can be priced appropriately for the market. The Joint Demand Response Parties support this modification, stating that it will allow the program to be called when it is truly needed, and not dispatched solely upon the heat rate methodology.[104] CLECA also supports the modification, noting that adding a price trigger should improve integration of CBP into the CAISO market because the market dispatches based upon price.[105] Furthermore, the Joint Demand Response Parties recommend that the Commission adopt a price component to the dispatch trigger for all three Utilities.[106]

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[104] Joint Demand Response Parties Comments at 18.

[105] CLECA at 5.

[106] Joint Demand Response Parties Comments at 18.

ORA opposes the proposal stating that approval of an unknown price component would make it difficult to address in an Advice Letter without direction from the Commission on the appropriate methodology. SCE clarifies that it could propose both a specific price trigger and a proposed methodology in an advice letter, to which stakeholders would have the opportunity to protest or respond.[107]

We find the proposal reasonable in that it improves the feasibility of integrating CBP into the CAISO market. While ORA's concern regarding approval of an unknown price is well-founded, we agree with SCE that the required advice letter should include both the specific price trigger as well as a proposed methodology to preserve due process. Furthermore, we find it reasonable for both SDG&E and PG&E to adopt this modification. The three Utilities shall work together to create a methodology to determine the price trigger and file advice letters no later than 45 days from the issuance of this decision proposing a price trigger to add to the CBP dispatch trigger.

We acknowledge that CBP is only one program facing this challenge; other programs may require further development to better align trigger conditions with CAISO market integration. The requirements directed in this decision will support the consideration of additional program changes in future years.

7. Comments on Proposed Decision

The proposed decision of ALJ Hymes in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by the CAISO, Joint Demand Response

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[107] SCE Response at 6.

Providers, ORA, PG&E, SDG&E and SCE on May 23, 2016, and reply comments were filed by Joint Demand Response Providers, ORA, PG&E, SDG&E and SCE on May 31, 2016. In response to comments on the proposed decision, corrections and clarifications have been made throughout this decision. We address certain comments below.

SCE requests that the Commission consider a joint proposal between it and Southern California Gas Company to provide matching incentives of $50 on qualifying programmable communicating thermostats and smart thermostats for the SCE PTR-ET-DLC program. The proposal includes joint marketing to the two service territories, areas of which overlap. We do not adopt this proposal as it is new information to the record of this proceeding.

The Joint Demand Response Parties requests the Commission to address the changes to PTR it proposed in its March 2, 2016 Comments: 1) SCE should define the hours of dispatch as 1:00 p.m. to 7:00 p.m. in order to maintain full participation; and 2) replace performance payments with a fixed seasonal incentive to make the incentive clearer and more reliable to customers and implementing an additional incentive for third parties to recruit more customers.[108] In response, SCE reiterated its March 14, 2016 reply comments stating that limited dispatches to the six-hour time period may limit the program's ability to be used to mitigate electric supply shortages.[109] SCE also explained that recruiting more customers does not ensure the customer will reduce load during an event but a performance payment should provide that

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108 Joint Demand Response Parties Opening Comments at 10-11 citing its March 2, 2016 Comments at 21.

109 SCE Reply Comments at 4 citing March 14, 2016 Comments at 4.

incentive.[110] We do not find the Joint Demand Response Parties recommendations to be improvements to the PTR program and hence, do not adopt them.

In response to comments to the proposed decision, we revised the proposal for 2017 Summer Discount Plan marketing funds, which we address here.

SCE questioned a proposed requirement to file a Tier Two Advice Letter requesting authority to spend the $1 million in 2017 marketing funds for the Summer Discount Plan by providing data that indicates whether the 2016 marketing efforts led to either a decrease in the attrition of the program or an increase in participation. SCE stated that it did not assert that additional marketing would result in reduced attrition or higher program participation levels. SCE requested that the Commission either eliminate the required advice letter or revise it to demonstrate that the increased marketing efforts led to higher enrollment. SCE noted that it is unnecessary to demonstrate a direct relationship between marketing and enrollment, even if one were capable of quantifying.

While we understand the urgency of the Aliso Canyon gas leaks and its potential impact, we cannot justify using ratepayer funds for marketing activities that may produce no benefits to the program. Our purpose in increasing demand response efforts in the LA Basin Local Capacity area is to prevent power outages. Ratepayer funds should be directed to activities where there is a strong

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[110] *Ibid.*

potential of positive impact. Hence, we decline to approve the additional $1 million in 2017 marketing funds for the Summer Discount Plan.

8. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and Kelly A. Hymes is the assigned ALJ in this proceeding.

Findings of Fact

1. The Aliso Canyon Gas Storage Facility experienced a natural gas leak on October 25, 2015.

2. On January 6, 2016, Governor Brown proclaimed a state of emergency in Los Angeles County due to the leak.

3. The Commission has been directed to take all actions necessary to ensure the continued reliability of natural gas and electricity supplies in the coming months during the moratorium on gas injections into the Aliso Canyon Facility.

4. AC Cycling programs are relatively fast demand response and typically provide reasonable performance levels.

5. The Aliso Canyon Risk Assessment Technical Report found that generating resources served by Aliso Canyon represents nearly 70 percent of the local capacity resources identified in the CAISO local capacity requirements for the Los Angeles (LA) Basin Local Capacity Area.

6. The March 23, 2016 Ruling directed that all Aliso Canyon proposals shall focus on the geographic regions affected by the gas leakage.

7. No party opposes SCE's proposal to temporarily reduce the economic dispatch hours to 20 hours.

8. A decrease in the minimum threshold should decrease the rate of attrition for SCE's Summer Discount Plan.

9. Program changes in reaction to the gas leakage at Aliso Canyon are only applicable to the 2016 and 2017 program years.

10. SCE provides no evidence that additional marketing will alleviate the attrition seen in the Summer Discount Plan or increase the participation rate.

11. SCE makes no attempt to improve its Peak Time Rebate or its Peak Time Rebate Enabling Technology programs.

12. SCE filed an Advice Letter on December 9, 2015 requesting to discontinue its PTR and PTR-ET programs.

13. The December 9, 2015 Advice Letter has been suspended.

14. SCE has not begun the required system changes and outreach for the discontinuance of the PTR and the PTR-ET programs.

15. It is reasonable to continue the PTR and the PTR-ET programs through 2016.

16. It is reasonable to authorize a budget of $600,000 to discontinue the PTR and PTR-ET programs in 2017.

17. The PTR-ET DLC program with a $75 incentive is cost-effective.

18. Nest provides no evidence to support its conclusion that a $100 incentive would provide higher participation rates in the PTR-ET DLC than a $75 incentive.

19. Nest provides no evidence to support its conclusion that a $100 incentive would result in 50,000 or more customers participating in the PTR-ET DLC.

20. SCE should make every effort to coordinate its demand response programs with its other demand side programs to mitigate the effects of the Aliso Canyon leak.

21. The scope of this proceeding does not include authorization of directives or funding for demand side management programs except the demand response programs.

22. The March 23, 2016 Ruling directed SCE to propose "conducting a custom demand response auction mechanism targeted at the areas most affected, or adjusting the focus of the current auction mechanism."

23. SCE did not propose a custom or adjusted demand response auction mechanism.

24. SCE presented no argument that a custom or adjusted auction mechanism would not be relevant or appropriate.

25. The current auction mechanism is not appropriate to address the issues of Aliso Canyon.

26. A custom auction mechanism may be necessary to adequately address the potential shortages.

27. A public stakeholder process would be appropriate for finalizing the specifics of a SCE customer auction mechanism.

28. It is appropriate to provide a strong starting point for the SCE custom auction mechanism.

29. The Commission has not made a determination on the Energy Division Staff Proposal regarding the use of fossil-fueled generation in demand response programs.

30. It is not appropriate to address the Staff Proposal in either a bridge funding decision or the issue regarding the gas leak at Aliso Canyon.

31. The current DRAM pilots specify that only non-fossil generation and storage that meets certain greenhouse gas criteria are allowed to be coupled with a DRAM resource.

32. All three Utilities previously requested to discontinue its Demand Bidding Program.

33. SCE requests to delay the discontinuance of the Demand Bidding Program until 2017.

34. Demand response program changes addressing the Aliso Canyon leak shall be targeted to the LA Basin.

35. The Demand Bidding Program resources are currently in place.

36. The Demand Bidding program has proven performance levels.

37. The limited continuation of Demand Bidding Program addresses the requirements that proposals target the affected area in 2017 and can be quickly deployed.

38. The proposed increased targeted marketing in BIP and API in 2017 to potential customers should result in additional load impacts.

39. SCE has sufficient space under the two percent cap on reliability programs.

40. The September Guidance Ruling instructed parties that proposal resulting in material facts in dispute and requiring evidentiary hearings would not be considered in the 2017 bridge funding decision.

41. The two percent reliability program cap is an issue that could result in material facts in dispute and require an evidentiary hearing.

42. The Commission is intent on fully integrating supply side programs into the CAISO market.

43. Given the nascent nature of the market, the Commission will not consider a program fully integrated unless all enrolled customers are integrated.

44. Historical program load impacts indicate that the demand bidding program has never achieved a strong showing of performance due to its design.

45. The Commission has adopted a policy of pursing demand response supply resources that can be integrated into the CAISO market.

46. The CAISO market does not permit participation of customers in two demand response providers' resources that have overlapping active periods.

47. Maintaining the demand bidding program for dual participation purposes is not a sufficient reason to continue the program.

48. The demand bidding program does not meet the requirements necessary to be considered a demand response supply resource.

49. The continuation of the demand bidding program would require significant and costly changes.

50. It is reasonable to continue SCE's demand bidding program through 2017 to alleviate the effects of the Aliso Canyon gas leakage.

51. It is reasonable to authorize the elimination of the demand bidding program for PG&E and SDG&E in 2017 and for SCE in 2018.

52. The Commission anticipates issuing a decision in R.13-09-011 to provide guidance to the Utilities for demand response activities and budgets in 2018 and beyond.

53. It is not possible to determine at this time whether the Commission will adopt a demand response auction mechanism for demand response in 2018 and beyond.

54. The 2016 auction process for the DRAM pilot is considered to be successful.

55. It is anticipated that the 2017 auction process for the DRAM pilot will likely be successful.

56. It is prudent and reasonable to continue, at the very least, the current form of the demand response auction mechanism pilot for a 2018 pilot.

57. It is important for the Utilities to be prudent and sensible in selecting and approving bids in the third demand response auction mechanism pilot.

58. The Commission has previously expressed a desire to adopt a statewide Automated Demand Response program with common program rules and incentive levels.

59. The Utilities' ADR program proposals are similar.

60. It is reasonable to adopt a statewide ADR program across the Utilities.

61. The Base Interruptible Program is dispatched infrequently.

62. The infrequent dispatch of the BIP makes the investment in ADR devices less valuable than investments in programs with more frequent dispatch.

63. The SCE ADR Express program parameters are reasonable for customers with peak demands of 50 to 499 kW.

64. The Commission previously denied a request to provide ADR customers 100 percent of incentives upon project completion as it found that a one-year investment is a reasonable minor inconvenience in comparison with the improved program cost-effectiveness.

65. The Guidance Ruling stated that ADR programs and technologies are key factors in advancing demand response.

66. A $200 per kW incentive is reasonable for increasing participation but maintaining cost-effectiveness.

67. An incentive cap of 75 percent of total project costs ensures cost-effectiveness while providing incentive levels to increase participation.

68. The Guidance Ruling directed the Utilities to address improvements in the ADR programs.

69. The Base Interruptible Program was dispatched three times during 2014-2015.

70. Providing an ADR device to a customer who only uses the devices three times in two years is not an improvement to ADR programs.

71. The purpose of the Utilities' over generation or over supply pilots is not to address overarching issues regarding storage for demand charge management that are currently being addressed in R.15-03-011.

72. Information gathered from the three over supply pilots can be useful to the demand response rulemaking as well as the storage rulemaking.

73. It is reasonable to approve the Utilities over supply pilots.

74. It is reasonable for the utilities to fund a total of $1 million in demand response research funding for 2017.

75. Critical Peak Pricing, Real Time Pricing, and Time of Use are rate programs.

76. Peak Time Rebate is a tariffed program whose customers receive incentives for a particular action.

77. Funding for the Peak Time Rebate program is more appropriately requested in a demand response program application process.

78. Consistency, but itself, is not necessarily a correct approach.

79. SDG&E provides no evidence of any barriers to consolidating the demand response funding requests.

80. PG&E, SDG&E and SCE are capable of consolidating all demand response program activities, including incentives into a demand response application process.

81. The Commission discontinued the marketing of the Base Interruptible Program in D.12-04-045.

82. PG&E stated that it withdraws its request to resume the marketing of the BIP.

83. It is reasonable to allow PG&E to withdraw its request to resume the marketing of the BIP.

84. Adjusting the day-ahead notification time in PG&E's CBP will provide resources that receive market awards sufficient time to be dispatched.

85. PG&E agreed to day-ahead notification language requested by the Joint Demand Response Parties.

86. It is reasonable to adopt the following CBP tariff language and require PG&E to update its tariff to make this change: "notifications shall be sent as soon as reasonably possible upon receipt by PG&E, but no later than 4:00 p.m. the day prior to the dispatch.

87. The past practice of the Commission has been to focus on the TRC results in analyzing cost-effectiveness of demand response programs.

88. Inflation should not be the reason to increase incentives.

89. The CBP with an increased incentive may be more desirable to customers transitioning from the AMP program.

90. Not approving the proposed increased incentive could lead to a loss of demand response resources from former AMP customers considering enrollment in the CBP.

91. The CBP with the increased incentives is cost-effective.

92. It is reasonable to increase PG&E's CBP incentive by 4.5 percent.

93. The demand response auction mechanism is a pilot and remains under development.

94. The demand response auction mechanism pilot penalty structure could change because it is a pilot.

95. The risks for Utilities are greater in the CBP and AMP programs than in the demand response auction mechanism pilot.

96. The current CBP payment/penalty structure provides for the inherent Utility risks.

97. It is reasonable to continue using the current CBP payment/penalty structure.

98. PG&E's proposed 2017 integration budget includes the costs of integrating an existing portfolio of demand response programs, including programs available to third party aggregators.

99. Third party demand response direct participation is in the initial implementation step.

100. Further review of third party demand response direct participation is required to determine whether additional costs are reasonable.

101. It is important to ensure adequate funding such that the existing portfolio is able to be integrated into the market.

102. Because direct participation is in the initial implementation step, it is not possible to compare the costs of direct participation integration with the costs to integrate utility demand response programs, at this time.

103. PG&E's budget request for integrating its current demand response programs into the CAISO market is reasonable.

104. TURN requests a clarification in SCE's proposed BIP tariff language requiring a firm service level.

105. TURN's proposed language clarification is similar to language elsewhere in the BIP tariff requiring a firm service level.

106. The proposed clarifying BIP tariff language requires that a re-test occur if a customer asks for a new firm service level.

107. The proposed re-test should lead to increased reliability from the customer asking for the new firm service level.

108. It is reasonable to have consistent language in a tariff.

109. The purpose of SDG&E's Summer Saver pilot is to test the viability of the technology for direct access customers.

110. SDG&E's Summer Saver pilot should expand choices for direct access customers.

111. SDG&E's Summer Saver pilot is not duplicative of other programmable thermostat pilots.

112. ADR device investments may not be recoverable through a Reliability program.

113. SDG&E's proposed Armed Forces pilot is a one year pilot which uses ADR devices through the BIP.

114. Historically, Reliability programs are not dispatched often in a one-year time span.

115. A limited amount of data will be captured in a one-year pilot program that is rarely dispatched.

116. The Navy has identified over 300 sites where it is targeting the installation of ADR devices.

117. It is unlikely that the Commission will recover the investment of over 300 ADR devices through a program that is dispatched infrequently.

118. The Navy has indicated a great deal of interest in participating in the demand response program.

119. The Navy could provide a significant demand response load impact through a CBP-like program.

120. The Guidance Ruling directed the Utilities to include, in the 2017 demand response proposals, changes that balance the desire by the Commission for 2017 improvements while taking into account that 2018 and beyond programs will most likely require bigger improvements.

121. The AMP program provides a lower number of dispatches in comparison with the CBP.

122. AMP dispatch hours are based on CAISO awards.

123. There is no evidence that the demand response auction mechanism will result in more dispatches than the AMP program.

124. It is reasonable to allow SCE to continue the AMP contracts for one year, as currently negotiated.

125. No party opposes SCE's request to remove BIP customers for non-performance.

126. It is reasonable to adopt the request by SCE to remove BIP customers for non-performance.

127. The record of this proceeding has no data on the alleged costs to allow BIP customers to aggregate across accounts.

128. It is possible that the BIP aggregation option might become more useful once BIP is integrated into the CAISO market.

129. It is reasonable to collect cost data on the BIP aggregation option.

130. SCE's proposal to adopt a price component to the dispatch trigger for CBP improves the feasibility of integrating CBP into the CAISO market.

131. It is reasonable for the three Utilities to develop a price component to the dispatch trigger for CBP.

132. Each Utility shall file an advice letter proposing the specific price trigger for the CBP as well as the proposed methodology.

Conclusions of Law

1. The Commission should require SCE to limit marketing for its Summer Discount Plan proposal to the LA Basin Local Capacity Area.

2. The Commission should reduce the economic dispatch hours from forty to twenty for SCE's Summer Discount Plan.

3. The Commission should adopt SCE's Summer Discount Plan proposal.

4. The Commission should authorize additional funding for SCE's Summer Discount Plan proposal.

5. The Commission should allow SCE to continue its PTR and PTR-ET programs through the end of 2016.

6. The Commission should authorize funding in 2017 to discontinue SCE's PTR and PTR-ET programs in 2017.

7. The Commission should allow SCE to continue its DBP through the end of 2017.

8. It is not necessary to suspend the two percent cap for reliability programs for SCE, PG&E or SDG&E.

9. The Commission should eliminate the demand bidding program, except where noted to provide reliability in the Los Angeles Basin through 2017.

10. The Commission should authorize the development of a third demand response auction mechanism pilot.

11. The Commission should maintain the 60-40 incentive split in the ADR program.

12. The Commission should balance increased participation with ensuring cost-effectiveness in the ADR program.

13. The Commission should adopt the policy that California Demand Response Reliability programs are not eligible for ADR programs.

14. The Commission should approve the over supply pilots proposed by each of the Utilities.

15. The Commission should direct the Utilities to fund a total of $1 million in demand response research funding for 2017.

16. The Commission should increase PG&E's CBP incentive by 4.5 percent.

17. The Commission should adopt the SCE BIP tariff language change as requested by TURN.

18. The Commission should approve SDG&E's Summer Saver pilot.

19.

20. The Commission should adopt a placeholder for a future Armed Forces pilot that includes ADR devices with a program that makes better use of the technology.

21. The Commission should extend SCE's AMP contracts for one year.

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company shall implement its Summer Discount Plan proposal for addressing the gas leak at the Aliso Canyon Gas Storage Facility but shall target marketing only in the Los Angeles Basin Local Capacity Area.

2. Southern California Edison Company is authorized to establish a balancing account to record the Aliso Canyon mitigation expenses authorized in this decision.

3. Southern California Edison Company is authorized to record, in the balancing account established in this decision, up to $2.8 million of 2016 Summer

Discount Plan expenses as approved in this decision and up to $3.178 million of 2017 Summer Discount Plan expenses approved in this decision.

4. Southern California Edison Company (SCE) shall reduce the minimum economic dispatch hour for residential Summer Discount Plan to 20 hours in 2016 and 2007. SCE shall file a supplement to advice letter 3320-E to implement this change to the appropriate tariff.

5. Southern California Edison Company shall withdraw its Advice Letter requesting to discontinue its Peak Time Rebate and Peak Time Rebate Enabling Technology tariffs.

6. Southern California Edison Company shall implement its Peak Time Rebate Enabling Technology Direct Load Control proposal for addressing the gas leak at the Aliso Canyon Gas Storage Facility.

7. Southern California Edison Company is authorized to record in the balancing account established in this decision up to $2.25 million of 2017 Peak Time Rebate expenses as approved in this decision.

8. Southern California Edison Company shall implement its Demand Bidding Program proposal for addressing the gas leak at the Aliso Canyon Gas Storage Facility.

9. Southern California Edison Company is authorized to record in the balancing account established in this decision up to $255,000 of 2017 Demand Bidding Program expenses as approved in this decision.

10. Southern California Edison Company is directed to inform the Commission, in its monthly Aliso Canyon updates, whether it anticipates reaching the two percent cap on reliability programs.

11. Southern California Edison Company (SCE) is authorized to implement a custom stand-alone demand response auction mechanism. If SCE chooses to

implement such a mechanism, SCE shall meet with the Commission's Energy Division, representatives of the California Independent System Operator and other stakeholders, within 10 days of the issuance of this decision, to finalize a custom stand-alone demand response auction mechanism with the same contract and provisions of the 2017 auction. The customer auction shall include the following five modifications:

a. Geographically targeted to the Los Angeles Basin;
b. 30 minute dispatch requirement;
c. New resources only;
d. Three year contracts must be standard pro forma, and modified from the 2017 demand response auction mechanism pilot contract; and
e. Use of a pre-defined advice letter timeline.

12. Southern California Edison is authorized to record in the balancing account established in this decision a budget of up to $3 million dollars in 2016 and 2017 funds for the customer stand-alone auction mechanism authorized in Ordering Paragraph 11.

13. Southern California Edison Company shall implement its Base Interruptible Program proposal for addressing the gas leak at the Aliso Canyon Gas Storage Facility as proposed.

14. Southern California Edison Company shall implement its Agricultural Pumping Interruptible program proposal for addressing the gas leak at the Aliso Canyon Gas Storage Facility as proposed.

15. Southern California Edison Company is authorized to record, in the balancing account established in this decision, up to $42,000 of 2017 Agricultural Pumping Interruptible program expenses approved in this decision.

16. Demand response program are only considered fully integrated into the California Independent System Operators market when all delivered megawatts are able to be integrated into the market.

17. The request to eliminate the two percent cap on reliability programs is denied.

18. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) are directed to re-establish the demand response auction mechanism working group, open to all stakeholders of Rulemaking 13-09-011, in order to develop an auction in 2017 for a 2018 delivery. The working group shall create the third auction pilot using the 2017 auction mechanism as a starting point and taking into consideration the participation of the first two auctions. The working group shall develop a consensus proposal for the auction pilot and the Utilities shall file the proposal via a Tier Three Advice Letter no later than September 1, 2016.

19. The Commission's Energy Division shall ensure that the meetings of the demand response auction mechanism working group are properly noticed on the Commission's Daily Calendar.

20. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the Utilities) are authorized a 2016-2017 budget of up to $27 million for the continuation of the demand response auction mechanism pilot in the following breakdown for the Utilities: $3 million for SDG&E and $12 million each for PG&E and SCE. The Utilities are instructed to ensure that the winning bids fit portfolio needs and offer the best value to the ratepayers.

21. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) are directed to

seek funding and incentives for all demand response programs through the demand response application process beginning with 2018 and beyond applications.

22. The proposal filed by Pacific Gas and Electric Company (PG&E) for 2017 demand response programs and activities is adopted as modified herein:

a. PG&E shall continue the demand response auction mechanism pilot by holding an auction in 2017 for delivery in 2018, as described in this decision;

b. PG&E shall not increase marketing for its Base Interruptible Program;

c. PG&E, in implementing changes for integrating its Capacity Bidding Program into the California Independent Systems Operator market in 2017, shall allow participants of the program to break a resource into sub-10 megawatt resources and allow performance to be measured across all for the capacity available by each utility in the sub-LAP.

d. PG&E is authorized to revise its notification time for the Capacity Bidding Program to as soon as reasonably possible upon receipt of the California Independent System Operator market award by PG&E, but no later than 4:00 p.m. the day prior to the dispatch;

e. PG&E shall implement its Automated Demand Response program with the following parameters: offer an incentive of $200 per kilowatt of verified dispatchable load reduction not to exceed 75 percent of the total project costs with 60 percent of the incentives paid after installation, load shed test and enrollment in a qualified program and 40 percent paid after one year.

f. PG&E's Reliability Demand Response Programs are ineligible for Automated Demand Response incentives.

g. PG&E shall adhere to the milestones and deadlines it proposed in Table 1 of its March 24, 2016 comments, including items i. through iv below. Deviation from these items shall be noticed, within 30 days, by letter to the

Rulemaking 13-09-011 service list or its successor service list.

i. Completion of Customer Management System in the fourth quarter of 2016;

ii. Completion of Control Center Application and Process Orchestration Systems in the first quarter of 2017 for BIP, and the third quarter of 2017 for CBP and SmartAC;

iii. Completion of the registration of BIP resources as RDRR no later than May 1, 2017; and

iv. Completion of the registration of CBP and SmartAC no later than January 1, 2018.

23. Pacific Gas and Electric Company is authorized $55.29 million in bridge funding for 2017 demand response programs as specified in this decision.

24. The proposal filed by San Diego Gas and Electric Company (SDG&E) for 2017 demand response programs and activities is adopted as modified herein:

a. SDG&E shall continue the demand response auction mechanism pilot by holding an auction in 2017 for delivery in 2018, as described in this decision;

b. SDDG&E shall revise the tariff language for its Base Interruptible Program to clarify that a re-test is required if a customer seeks a new firm service level.

c. SDG&E, in implementing changes for integrating its Capacity Bidding Program into the California Independent Systems Operator market in 2017, shall allow participants of the program to break a resource into sub-10 megawatt resources and allow performance to be measured across all for the capacity available by each utility in the sub-LAP.

d. SDG&E's request to perform the Armed Forces pilot is denied. SDG&E is directed to design a pilot for the Armed Forces focusing on the use of automated demand response (ADR) technology. SDG&E is authorized a budget cap of $250,000 to perform this pilot. No later than September 1, 2016, SDG&E shall file a Tier Three Advice

Letter requesting approval of the newly designed Armed Forces ADR pilot.

e. SDG&E shall implement its Automated Demand Response program with the following parameters: offer an incentive of $200 per kilowatt of verified dispatchable load reduction not to exceed 75 percent of the total project costs with 60 percent of the incentives paid after installation, load shed test and enrollment in a qualified program and 40 percent paid after one year.

f. SDG&E's Reliability Demand Response Programs are ineligible for Automated Demand Response incentives.

25. San Diego Gas and Electric Company (SDG&E) is authorized $22.3 million in bridge funding for 2017 demand response programs as specified in this decision. The cost recovery methodology as proposed by SDG&E is approved.

26. The proposal filed by Southern California Edison Company (SCE) for 2017 demand response programs and activities is adopted as modified herein:

a. SCE shall continue the demand response auction mechanism pilot by holding an auction in 2017 for delivery in 2018, as described in this decision;

b. SCE is authorized to extend its existing Aggregator Managed Portfolio program contracts through 2017. ;

c. SCE's request to eliminate account aggregation in its Base Interruptible Program is denied. SCE shall provide cost data to determine whether elimination should occur in 2018. The cost data shall be included in SCE's application for 2018 Demand Response Program Budgets and Activities.

d. SCE, in implementing changes for integrating its Capacity Bidding Program into the California Independent Systems Operator market in 2017, shall allow participants of the program to break a resource into sub-10 megawatt resources and allow performance to be measured across all for the capacity available by each utility in the sub-LAP.

e. SCE shall implement its Automated Demand Response program with the following parameters: offer an incentive of $200 per kilowatt of verified dispatchable load reduction not to exceed 75 percent of the total project costs with 60 percent of the incentives paid after installation, load shed test and enrollment in a qualified program and 40 percent paid after one year.

f. SCE's Reliability Demand Response Programs are ineligible for Automated Demand Response incentives.

27. Southern California Edison Company is authorized $50.28 million in bridge funding for 2017 demand response programs as specified in this decision.

28. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) shall work together to create a methodology to determine a price trigger for the Capacity Bidding Program (CBP) and file tier three advice letters no later than 45 days from the issuance of this decision proposing the price trigger to add to the CBP dispatch trigger.

29. Rulemaking 13-09-011 remains open to address outstanding phase two and three issues and provide guidance for utility demand response programs for program years 2018 and beyond.

This order is effective today.

Dated ____________________________, at San Francisco, California.