

Decision 17-12-003 December 14, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric
Company (U39E) for Approval of Demand
Response Programs, Pilots and Budgets for
Program Years 2018-2022.

Application 17-01-012

And Related Matters.

Application 17-01-018

Application 17-01-019

**DECISION ADOPTING DEMAND RESPONSE ACTIVITIES
AND BUDGETS FOR 2018 THROUGH 2022**

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ATTACHMENT 1 - Settlement Agreement of Pacific Gas and Electric Company, California Large Energy Consumers Association, Enernoc, Inc., Cpower, Inc., Energyhub, Inc., Ohmconnect, Inc., Electric Motor Werks, Inc., and California Efficiency + Demand Management Council On Specified Issues in Application 17-01-012.

(Pages 12-31 of the A17-01-012 *et al.* Motion of Settling Parties for Adoption of Settlement dated June 26,2017.)

ATTACHMENT 2 - Amendment 1 to Correct Error Settlement Agreement of Pacific Gas and Electric Company, California Large Energy Consumers Association, Enernoc, Inc., Cpower, Inc., Energyhub, Inc., Ohmconnect, Inc., Electric Motor Werks, Inc., And California Efficiency + Demand Management Council on Specified Issues in Application 17-01-012.

(Pages 4-15 of the A17-01-012 et al Motion of Settling Parties dated July 21, 2017.)

ATTACHMENT 3 - 2018 – 2022 Demand Response Program Budgets

DECISION ADOPTING DEMAND RESPONSE ACTIVITIES AND BUDGETS FOR 2018 THROUGH 2022

Summary

By this decision, the Commission adopts demand response activities and budgets for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) (collectively, the Utilities) to conduct demand response programs, pilots and associated activities for the years 2018 through 2022 as described herein. We authorize a budget of \$333.272 million for PG&E, \$751.027 million for SCE and \$78.618 million for SDG&E.

By this Decision, we also determine that SDG&E has less than satisfactory cost-effectiveness ratios for its demand response programs and portfolio; this necessitates closer oversight and monitoring. We direct SDG&E to (1) reduce its administrative budget by ten percent across all programs; (2) meet with Energy Division on a quarterly basis to discuss its progress in improving the cost-effectiveness of its programs and portfolio, and (3) file Tier 1 level advice letters in January 2019 and 2020 demonstrating the costs of its programs administered the previous year as well as the cost-effectiveness analyses results of these programs.

In order to support pilot programs that will assist the Commission in shaping its policy on targeting demand response in transmission constrained local capacity areas and disadvantaged communities, this Decision authorizes a \$2.5 million budget for future pilot programs to increase demand response customer enrollments in those areas and communities. A Ruling will be issued subsequently to introduce a straw proposal for these pilots followed by a

workshop hosted by the Commission's Energy Division. Comments on the proposal will lead to utility implementation guidance in a future decision.

Also in this Decision, the Commission expresses its support for the limited integration of demand response and energy efficiency activities, as described in the Energy Division Staff Proposal, should the budget request for these activities be approved in the energy efficiency application, Application 17-01-013 et al.

This proceeding remains open to consider additional information in this proceeding.

1. Background

The Commission broadly defines demand response as reductions, increases, or shifts in electricity consumption by customers in response to either economic signals or reliability signals. Economic signals come in the form of electricity prices or financial incentives, whereas reliability signals appear as alerts when the electric grid is under stress and vulnerable to high prices. Demand response programs aim to respond to these signals and maximize ratepayer benefit.

1.1. Procedural History

Commission Decision (D.) 16-09-056, adopting guidance for future demand response portfolios and modifying D.14-12-024, directed Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), and Southern California Edison Company (SCE) to file applications requesting approval and funding for 2018-2022 demand response portfolios for existing models of demand response programs and activities pursuant to the guidance provided in the decision. As directed by D.16-09-056, on January 17, 2017, PG&E, SDG&E, and SCE (jointly, the Utilities) filed applications for existing

models of demand response programs for their 2018-2022 demand response portfolios.

Pursuant to Rule 7.4, the Administrative Law Judges' ruling dated February 16, 2017, consolidated these applications into a single proceeding, Application (A.) 17-01-012 et al., as they addressed similar funding and program planning issues. The same ruling set a prehearing conference for March 1, 2017, and also clarified that due to the consolidation of three Applications, the deadline to file protests to the three Applications would be February 27, 2017. California Energy Storage Alliance (CESA), Office of Ratepayer Advocates (ORA), Utility Consumers' Action Network (UCAN), California Large Energy Consumers' Association (CLECA), and CPower, EnerNOC, Inc., EnergyHub, Converge, Inc., (together, the Joint Demand Response Parties) filed timely protests; SolarCity Corporation, California Energy Efficiency Industry Council,¹ and OhmConnect, Inc. filed timely responses to the Applications.

On March 1, 2017, a prehearing conference was held to determine parties, discuss the scope, the schedule, and other procedural matters. Following the prehearing conference, the assigned Commissioner and Administrative Law Judges jointly issued a ruling on March 15, 2017 (Scoping Memo) that set out the scope of the proceeding, which is discussed below.

Parties served testimony on May 11, 2017 and rebuttals on June 5, 2017. During June 19 -21, 2017, parties participated in three days of evidentiary hearings. Following the evidentiary hearings, the parties received briefing guidance from the assigned Administrative Law Judges in a July 1, 2017 Ruling.

¹ The California Energy Efficiency Council is now referred to as the California Efficiency + Demand Management Council.

In the ruling, parties were directed to include in their briefs responses to questions pertaining to limited integration of demand response technologies with energy efficiency activities and the targeting of demand response in transmission constrained local capacity areas and disadvantaged communities. The same ruling also revised the deadlines for parties to submit opening briefs and reply briefs.

Parties filed briefs on July 24, 2017 and reply briefs on August 4, 2017. The assigned Administrative Law Judges submitted the record of this proceeding on August 4, 2017. A ruling issued on November 3, 2017 granted a motion and admitted an amendment to the Settlement addressed in this Decision; the ruling resubmitted the record of this proceeding on November 3, 2017. The Joint Demand Response Parties requested oral argument in their briefs. While the oral argument was noticed for December 6, 2017, extenuating circumstances led to less than a quorum of Commissioners available. Parties agreed to waive oral argument; hence the oral argument was not rescheduled.

1.2. Scope of Proceeding

The scope of this proceeding is a review of the three 2018-2022 demand response applications for compliance and reasonableness. It is crucial that what we approve in the Applications advances the goal, principles, and guidance adopted in D.16-09-056 and complies with the directives in D.16-09-056, as well as all other relevant directives in prior Commission decisions and rulings. Accordingly, demand response programs and their associated budgets requested in the Applications have been reviewed in three categories: compliance, reasonableness, and cost-effectiveness, all of which are discussed in further detail below. Other matters, such as fund shifting, revenue requirement and cost

recovery, coordination with other proceedings, are also included in the scope of this proceeding and addressed in this decision.

In addition to the review of the demand response programs, several policy issues were considered in this proceeding. These include targeting demand response programs in constrained local capacity planning areas and disadvantaged communities as well as limited integration of demand response activities with energy efficiency programs.

2. Issues Before the Commission

The following issues are included in the scope of this proceeding:

- Do the applications of PG&E, SCE, and SDG&E requesting approval of demand response programs and budgets for Program Years 2018 through 2022 advance the goal, principles, and guidance adopted in D.16-09-056 and comply with the directives in D.16-09-056, as well as all other relevant directives listed in prior Commission decisions and rulings?
- Are the Utilities' proposed changes to demand response programs and activities, including pilot recommendations, reasonable and should they be adopted? Similarly, are parties' proposed changes to Utilities' programs reasonable? In particular, we will consider:
 - How to address the current two percent cap on reliability demand response.
 - Whether to change SCE's Technology Incentive Program.
 - Whether the Utilities' programs sufficiently integrate Energy Management Technologies incentivized pursuant to AB 793 as codified in Public Utilities Code Section 717.

- Whether the Utilities' programs sufficiently address data access issues for third-party demand response providers.²
- Whether OhmConnect's proposal regarding marketing, education, and outreach is reasonable and should be adopted?
- Are the Utilities' proposed programs and portfolios cost-effective pursuant to cost-effectiveness protocols adopted in D.15-11-042 and D.16-06-007? If they are not cost-effective, should they be adopted?
- Are the Utilities' requested budgets to implement the proposed programs and cost and rate recovery requests, including continued fund shifting flexibility, reasonable?
- Should the Commission consider whether the Utilities' proposed programs and portfolios adequately focus on locating demand response participants in particular geographic areas, such as disadvantaged communities or areas of highest value to the grid that could also defer or displace investment in generation, transmission, and distribution? If so, could the Utilities increase utilization of demand response in disadvantaged communities, or displace conventional generation in locally constrained transmission areas, or should the Utilities apply approaches being developed in Rulemaking (R.) 14-08-013, including locational net benefit analysis or integrated capacity analysis to demand response resources in this cycle of program implementation?
- For issue areas that are being determined in other proceedings or venues, do the Utilities' proposed program

² Third-party demand response providers are non-utilities and non-investor-owned utilities providing demand response services through their own demand response programs. Demand Response aggregators combine customer load and provide that load to a utility-administered program such as the Capacity Bidding Program through a contract with the utility.

designs provide reasonable direction to demand response program participants until those issues are completely resolved in those venues? These issue areas would include:

- Response time requirement on local resource adequacy resources;
- Data access issues; and
- Baselines.
- Is PG&E's proposal for post-2019 Demand Response Auction Mechanism cost recovery reasonable and should it be adopted?
- Should the Commission explore joint activities in demand response and energy efficiency by integrating funding and program implementation in a limited-manner, *e.g.* targeting specific controls, conducting necessary studies?

3. Summary of Applications

The Applications submitted by the Utilities include proposals for demand response activities and programs. The Applications also request budgets for these activities. The following sections briefly describe the Applications, including the proposed budgets, while highlighting a few specific proposals for each utility.

3.1. PG&E (A.17-01-012)

PG&E proposes modifications to its existing programs, including the Capacity Bidding Program, Base Interruptible Program, SmartAC Program, and Automated Demand Response Program. According to PG&E, these modifications will enable PG&E to meet the needs of the grid in a reliable and cost-effective way, further support third-party market participation, and better serve its customers.

With the proposed programmatic changes, PG&E estimates over 500 Megawatts (MW) load impact per year over the 2018-2022 program cycle, as shown in Table 1.³

Table 1 Ex Ante Load Impacts by Demand Response Program (MW) August 1-in-2 PG&E System Peak Conditions					
DR Resource	2018	2019	2020	2021	2022
Base Interruptible Program	330	330	330	330	330
Capacity Bidding Program	49	52	56	59	62
Peak Day Pricing	54	54	55	55	55
Permanent Load Shifting	3	3	3	2	2
SmartAC	72	74	76	79	81
SmartRate	22	22	22	22	22
Total	529	535	541	546	552

In its Application, PG&E proposes to continue two pilots, Supply Side II Demand Response pilot and the Excess Supply Demand Response pilot. One of the objectives of the Supply Side II Demand Response pilot is to determine customers' willingness to be dispatched frequently enough and over the range of hours necessary to meet local distribution needs and resource adequacy requirements. The Excess Supply Demand Response pilot aims to address mitigation of excess wind and solar supply situations. If approved as requested, both pilots would continue beyond 2017, with a proposed evaluation as part of the mid-cycle review.

³ PGE-01 at 5-5.

In addition to the above programmatic proposals, PG&E requests the Commission maintain the existing fund-shifting rules approved in D.12-04-045, authority to follow certain accounting treatments of its demand response related revenue requirement, and Commission direction for addressing costs related to the Demand Response Auction Mechanism in the post- 2019 period, if adopted as a permanent mechanism.

PG&E requests approval of a demand response budget of \$349.2 million for years 2018-2022, excluding DRAM funding, \$9.56 million less per year than was authorized in D.16-06-029 for 2017.⁴ PG&E explains that this reduction is due to “the closure of programs, completion of information technology system work required to integrate demand response programs with the California Independent Systems Operator (CAISO), and reduction in marketing expenses.”⁵ The budget includes incentives of \$194.52 million for the following programs: Base Interruptible Program, Capacity Bidding Program, AC Cycling, Auto Demand Response, and the two pilots.⁶

3.2. SCE (A.17-01-018)

SCE proposes numerous changes to its 2018-2022 demand response portfolio. These proposed changes include offering Base Interruptible Program incentives that provide higher value for resources that are able to meet 20-minute response requirements for local capacity resources, discontinuation of the Base

⁴ See PGE-08, and PGE-06, Chapter 6 at 1-2. PG&E submitted budget corrections amounting to an increase of \$594,591 from the original filing. The increase accounts for the updated benefit burdens for calculating labor costs, which were approved in the PG&E General Rate Case Decision 17-05-013.

⁵ PG&E Application at 14.

⁶ PGE-06 at 24.

Interruptible Program aggregation option, reprogramming Agricultural and Pumping Interruptible Program and Base Interruptible Program meters to record 5-minute interval data, and reducing annual capacity payment for the Peak Time Rebate program, among others.

In addition to the programmatic modifications, SCE requests re-examination of the reliability cap, changes to demand response integration rules, elimination of underutilized performance reports, categorizing programs and budgets consistent with resource bifurcation, and consolidation of the demand response and energy efficiency funding authorizations. In addition, SCE's Application requests approval of the Charge Ready demand response pilot, targeted for workplaces, fleets, destination centers, and multi-unit dwellings with charging stations, with the goal of examining charging behavior in this market segment.

With its proposed portfolio, SCE estimates around 1,000 MW average load impact per year for 2018-22, as shown in Table 2.⁷

Table 2 Ex Ante Load Impacts by Demand Response Program (MW) August 1-in-2 SCE System Peak Conditions					
DR Resource	2018	2019	2020	2021	2022
Agricultural and Pumping Interruptible	55	54	53	52	51
Base Interruptible Program 15 Minute	141	139	136	134	131
Base Interruptible Program 30 Minute	529	517	507	497	487
Summer Discount Program Residential	213	202	192	183	174
Summer Discount Program Commercial	47	40	38	36	34

⁷ SCE-03 at 23.

Capacity Bidding Program Day Of	46	46	46	46	46
Capacity Bidding Program Day Ahead	4	4	4	4	4
Save Power Days	31	38	46	54	61
Permanent Load Shifting	1	1	1	1	1
Total	1,066	1,042	1,024	1,007	991

SCE requests \$177.2 million funding for its 2018-2022 portfolio, excluding DRAM funding.⁸ While not requesting recovery of customer incentives in this application, SCE estimates customer incentives of \$586.512 million for 2018-2022 program years in the following programs: Agricultural Pumping Interruptible, Base Interruptible Program, Capacity Bidding Program, Summer Discount Plan, and Save Power Days.⁹

3.3. SDG&E (A.17-01-019)

SDG&E proposes to improve its supply side portfolio of existing programs by implementing programmatic changes. For example, for the AC Saver Program (formerly named Summer Saver), SDG&E proposes to extend the event window hours and extend the eligibility for the program to other air-conditioning control devices. SDG&E plans to review its programs in 2019 to determine whether program participation increased and cost-effectiveness improved; evaluate future potential for growth; compare the programs with the Demand Response Auction Mechanism pilot, and then propose to modify or eliminate programs that are not cost-effective, so that the utility can concentrate on cost-effective programs. SDG&E intends to focus primarily on its Base

⁸ SCE-11.

⁹ SCE-02 at 8, 14, 22, 31, and 34.

Interruptible Program and Technology Incentive Program for this effort. SDG&E believes that focusing on customer and aggregator recruitment and adjusting program budgets accordingly will help grow its programs, which will in turn improve the program cost-effectiveness.

In its Application, SDG&E also proposes two pilot programs, Armed Forces Pilot and Over Generation Pilot. The Armed Forces Pilot aims to test the Armed Forces' ability to participate in the Day-of Automatic (Auto) Demand Response program, whereas the Over Generation Pilot focuses on the role of distributed storage at times when there is excess renewable resources supply.

With these programmatic proposals, SDG&E estimates between 44 MW to 61 MW load impact per year over the 2018-2022 period, as shown in Table 3.¹⁰

Table 3 Ex Ante Load Impacts by Demand Response Program (MW) August 1-in-2 SDG&E System Peak Conditions					
DR Resource	2018	2019	2020	2021	2022
AC Saver Day-Ahead Non-Residential	2.9	2.8	2.7	2.6	2.5
AC Saver Day-Ahead Residential	7.4	8.6	10.4	12.8	15.4
AC Saver Day Of Non-Residential	2.2	2.2	2.1	2.1	2.1
AC Saver Day Of Residential	8	7.7	7.4	7.2	6.9
Armed Forces Pilot	2.3	2.9	3.7	4.7	6
BIP	6.7	6.8	6.9	7.2	7.1
Capacity Bidding Program Day Ahead	7.7	7.9	8.1	8.4	8.6
CBP Day Of	4.6	5	5.5	6.1	6.7

¹⁰ SGE-04 at LW-3.

Permanent Load Shifting	2.3	2.9	3.7	4.7	6
Total	44.1	46.8	50.5	55.8	61.3

SDG&E requests \$89.9 million funding for its 2018-2022 portfolio, excluding funding for the Demand Response Auction Mechanism pilot or a permanent mechanism.¹¹ This funding amount includes \$36.15 million in incentives paid to customers for the following programs: AC Cycling, Armed Forces Pilot and proposed program, Base Interruptible Program, Capacity Bidding Program, Technology Deployment Program and Technology Incentive Program. SDG&E also proposes to reduce budget categories from the current ten categories to six categories to have more flexibility in shifting funds.

4. Motion of the Settling Parties

On June 26, 2017, the Settling Parties filed *Motion of the Settling Parties for Adoption of Settlement on Specified Issues in Pacific Gas and Electric Application 17-01-012* (Joint Motion) and requested the Settlement's approval. In the Joint Motion, PG&E, CLECA, EnerNOC, Inc., CPower, Inc., EnergyHub, Inc., OhmConnect, Inc., Electric MotorWerks, Inc., and California Efficiency + Demand Management Council are identified as the Settling Parties and they represent third-party demand response providers, including residential demand response providers, large customers, energy efficiency interests, and PG&E. On July 26, 2017, SCE and SDG&E filed comments on the Joint Motion and the Settlement. PG&E and the Joint Demand Response Parties submitted reply comments on August 10, 2017. Due to a correction made in the Settlement,

¹¹ SDG&E Application at 2.

PG&E filed a motion for permission to submit the First Amendment to the Settlement (Amendment) on September 21, 2017.

Pursuant to Rule 12.1(b) of the Commission's Rules of Practice and Procedure, the Settling Parties provided timely notice of a settlement conference. The settlement conference was held on May 17, 2017.

As stated in the Joint Motion, the Settlement is the result of discussions held by PG&E pursuant to Rule 12. The Joint Motion explains that the Settling Parties held differing views on several issues and the Settlement therefore represents a negotiated compromise. The Settling Parties believe that the Settlement addresses each of the issues contained in the Settlement in a fair and balanced manner.

As briefly summarized below and entirely contained in Appendix A, the Settlement covers the following areas and resolves disagreements between the Settling Parties:

Table 4. Overview of Settlement¹²		
Program/ Issue Area	Sub Issue	Resolution
Base Interruptible Program and Capacity Bidding Program	Credit and Collateral Requirements	Remain unchanged. PG&E may submit a proposal in the mid-cycle review.
Base Interruptible Program	Notification Time for Base Interruptible Program Events	30-Minute dispatch time remains unchanged.
	Base Interruptible Program Day-Ahead Pilot	PG&E will conduct a pilot for bidding a small number of Base Interruptible Program customers' MW into the CAISO

¹² PG&E Opening Brief, July 24, 2017, at 9.

	Time-of-Use (TOU) Periods	market on a day-ahead basis. Time periods used to calculate the Base Interruptible Program incentive will correspond to the TOU periods approved in PG&E General Rate Case (GRC) Phase II or Rate Design Window (RDW) proceeding.
Reliability Cap		Maintains the cap approved in D.10-06-034.
Capacity Bidding Program	Tariff Changes	Two event duration options will be implemented.
	Penalty Structure	Remains unchanged.
	Residential Enrollment Process	Remains unchanged.
	Day-of-Option	Eliminated.
	Baselines	Requests a process to discuss.
Auto Demand Response		PG&E to start a stakeholder process to develop a list of residential Auto Demand Response-enabled end-use devices.
SmartAC		Remain unchanged.
Cost-effectiveness		Parties agree to the cost-effectiveness methodology used by PG&E, but reserve their right to contest the input assumptions.
Budget		Parties agree to PG&E's proposed budget, with the exception of marketing budget.

According to PG&E, modifications made to PG&E's original proposals are consistent with D.16-09-056, and recognize that further stakeholder process is needed to resolve certain issues.¹³ The resolution of the specific issues is described in more detail in the next section.

4.1. Issue Areas

The Settling Parties have addressed the following issues in the Settlement.

¹³ PG&E Opening Brief, July 24, 2017, at 8.

4.1.1. Credit and Collateral Requirements

The Settling Parties agree that PG&E will withdraw its proposal to add credit and collateral requirements to PG&E's Base Interruptible Program and Capacity Bidding Program and existing requirements will remain the same. PG&E may propose new requirements in another venue, no earlier than 2020.

4.1.2. Notification Time for Base Interruptible Events

The Settling Parties agree that the 30-minute notification time for Base Interruptible Program events will remain the same. Changes to dispatch timing requirements for Base Interruptible Program may be addressed in the appropriate proceeding if requirements for Base Interruptible Program to qualify for resource adequacy or local resource adequacy requirements are changed. In addition, PG&E will conduct a pilot in 2017 for bidding a small number of MWs into CAISO markets on a day-ahead basis. PG&E will initiate a stakeholder process in the first quarter of 2018 about the results of the pilot and its possible expansion. If the pilot proves to be successful, PG&E's proposal will be submitted in an advice letter. The Settling Parties reserve their rights to review and contest the advice letter. If the pilot is successful, PG&E aims to establish a permanent program by May 2018 and make the program available to customers by end of 2018, subject to Commission approval of the advice letter. If the program gets approved, the MWs in the Base Interruptible Program day-ahead market will not count towards the reliability cap approved in D.10-06-034. PG&E does not request additional funding for this pilot at this time.

4.1.3. Reliability Cap

The Settlement maintains the reliability cap approved in D.10-06-034. The Settlement recommends that a collaborative process led by the Commission's

Energy Division to discuss management of the cap should start in the first quarter of 2018.

4.1.4. Capacity Bidding Program

The Settling Parties agree on a number of issues related to Capacity Bidding Program:

- **Tariff Changes:** PG&E will implement two event duration options for Capacity Bidding Program. If these options get approved by the Commission, PG&E will add provisions into the tariff in order to protect Capacity Bidding Program aggregator bidding strategy and prices from release to unauthorized third parties and public disclosure, except as provided by law, regulation, and Commission order.
- **Penalty Structure:** The Settlement maintains the existing penalty structure, but it requires a collaborative process to determine a revised Capacity Bidding Program penalty structure to be submitted in an advice letter. PG&E may propose further changes to the penalty structure in the mid-cycle review.
- **Residential Enrollment:** The existing enrollment process remains the same. PG&E commits to conduct a Request for Information to identify best practices for customer authorization and enrollment process. Based on the finding of the request, PG&E will initiate a pilot to implement a digital enrollment process for the Capacity Bidding Program in 2018 or 12 months after the issuance of this Decision.
- The day-of option for the Capacity Bidding Program will be eliminated.
- The Settlement requests a Commission-initiated process to discuss baselines for retail settlement of demand response programs, after there is a Federal Energy Regulatory Commission (FERC) decision on alternative wholesale demand response baselines for the CAISO to inform the retail discussion.

The Settlement does not resolve the issue of PG&E's proposed operating hours and Capacity Bidding Program's cost-effectiveness.

4.1.5. Auto Demand Response

The Settlement requires PG&E to start a collaborative process within 60 days of the issuance of this Decision to develop of a list of residential automated demand response enabled end-use devices to be considered for eligibility for an Auto Demand Response incentive.

4.1.6. SmartAC

PG&E's SmartAC program will continue as proposed in PG&E's Application.

4.1.7. Budget and Cost-Effectiveness

The Settling Parties agree to PG&E's proposed budget for 2018-2022, with the exception of the marketing budget. The Settling Parties also agree on the cost-effectiveness method used by PG&E, but reserve their right to contest the input assumptions used.

4.2. Standard for Review of Settlements

The requirements for settlements are set forth in Article 12, Rules 12.1 through 12.7 of the Commission's Rules of Practice and Procedure. Rule 12.1(a) requires parties to submit a settlement by written motion within 30 days after the last day of hearing. This settlement was presented at the hearings and pursuant to the direction provided by the Administrative Law Judges, a motion requesting approval of the settlement was filed on June 26, 2017. The Settling Parties held a conference settlement on May 17, 2017 as required by Rule 12.1(b). Thus, the Settlement meets all requirements set forth in Rules 12.1(a) and (b).

The Commission must decide whether to approve the Settlement Agreement. The relevant criteria for Commission approval of settlements are stated in Rule 12.1(d) which provides that "[t]he Commission will not approve

settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.” In general, the Commission does not consider if a settlement reaches the optimal outcome on every issue. Rather, the Commission determines if the settlement as a whole is reasonable. A settlement agreement should also provide sufficient information to enable the Commission to implement and enforce the terms of the settlement. In the following sections, we discuss the terms of the Settlement before the Commission and determine whether it meets the standards of Rule 12.1(d).

4.3. Discussion and Analysis of the Proposed Settlement

Rule 12.1(d) states that the Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the record, consistent with law, and in the public interest. Furthermore, Rule 12.4(c) allows that the Commission may reject a settlement and instead propose alternative terms. While we determine, below, that the proposed Settlement does not, in fact, resolve all issues in this proceeding, we consider the process that the Settlement establishes to be a reasonable manner by which to address some of the issues included in the scope of this proceeding in a non-adversarial manner. As allowed by Rule 12.4(c), we propose one modification in this decision that resolves issues or leads to a resolution of issues. As provided for in Rule 12.4(c), we also provide the Settling Parties 15 days after the issuance of this decision to either accept the modification we propose in this decision or request other relief. No later than 15 days following the issuance of this decision, Settling Parties shall file a letter (as a compliance filing) in this proceeding stating whether they accept the modification adopted in this decision or if they request alternate relief.

We find the Settlement, as modified, to be reasonable in light of the record, consistent with the law, and in the public interest; thus we adopt the modified Settlement. We discuss each of these three aspects separately below.

**4.3.1. The Proposed Settlement, with Modification,
is Reasonable in Light of the Record**

We find the Settlement, as modified, to be reasonable in light of the record before us. We discuss two provisions of the Settlement below:

Settlement Provision on Budget: The Settling Parties agree to PG&E's proposed budget for 2018-2022, as presented in Table 6-2 in PG&E's testimony, with the exception of marketing as listed in Table 2-5 of PG&E's testimony.

As discussed in relevant sections, this decision modifies PG&E's proposed budget. As discussed in Section 6.11, the Permanent Load Shifting program will be eliminated from the Utilities' portfolios. Accordingly, we will not authorize the Permanent Load Shifting program budget request. Related marketing budget requests will be revised as well. Consequently, PG&E's authorized budget will be lower than what is proposed by PG&E in its Application. Given that the authorized budget will be different from the proposed budget the Settling Parties agree to, PG&E's proposed budget will no longer be applicable and the related provision will not be enforceable. Therefore, we do not approve Settlement provision H.

Settlement Provision on Cost-Effectiveness: The Settling Parties agree to the cost-effectiveness method, but reserve the ability to contest the inputs to PG&E's cost-effectiveness analysis. The Settling Parties also reserve the ability to raise proposals regarding cost-effectiveness method in the mid-cycle review.

D.10-12-024 adopted a method for estimating the cost-effectiveness of demand response activities. D.10-12-024 also required the Utilities to use the Protocols for all future cost-effectiveness analysis of demand response programs.

Even though we do not reject the settlement provision on cost-effectiveness, we note that determination of a cost-effectiveness method is outside the scope of this proceeding.

4.3.2. The Settlement, as Modified, is Consistent with the Law and Prior Commission Decisions

The Settlement, as modified, is consistent with law and prior Commission decisions. As discussed above, the Settling Parties have complied with the provisions of Rule 12 regarding Settlements.

The issues resolved in the Settlement, except the provision on cost-effectiveness, are within the scope of this proceeding. The Settling Parties contend that the Settlement is consistent with current law and is compliant with all applicable statutes and prior Commission decisions.

There are no terms within the Settlement that would bind the Commission in the future or violate existing law. Therefore, we find the Settlement consistent with the law.

4.3.3. The Settlement, as Modified, is in the Public Interest

The Settlement, as modified, is in the public interest for the following reasons. First, it resolves program-related issues by taking into account interest of diverse parties. It balances various interests at stake.¹⁴ The Settling Parties indicate that they represent a variety of interests. Third-party demand response providers, aggregators who serve residential and non-residential customers and large non-residential customer interests participated in the Settlement. It is the

¹⁴ See D.11-12-053, discussing settlements.

Settling Parties' belief that the Settlement serves the goals of most of parties in PG&E's Application 17-01-012.

As the Commission has previously acknowledged, "[t]here is a strong public policy favoring the settlement of disputes to avoid costly and protracted litigation," and when the settlement is fair and reasonable in light of the whole record. This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.

It is established Commission policy that "[a]s long as a settlement, taken as a whole, is reasonable in light of the record, consistent with law, and in the public interest, it will be adopted."¹⁵ We find the Settlement, with our modification, to be reasonable in light of the record, consistent with the law, and in the public interest; thus we adopt the Settlement provisions A through G.

As allowed by Rule 12.4(c), we provide the Settling Parties 15 days after the issuance of this decision to either accept the modification we propose in this decision or request other relief. No later than 15 days following the issuance of this decision, the Settling Parties shall file a letter in this proceeding stating whether they accept the modification adopted in this decision or if they request alternate relief.

5. Compliance with Commission Directives

This Decision finds that the demand response portfolios of the Utilities generally advance the goal, principles, and guidance adopted in D.16-09-056 and comply with the directives in D.16-09-056 and prior related directives. Each of the Utilities maintains that their application meets the goal and principles

¹⁵ D.05-03-022 at 8-13.

adopted by the Commission. However, as detailed below, there are concerns regarding competitive inequality between utility-administered demand response programs and third-party demand response programs. These concerns are introduced in this section, but addressed in the reasonableness section of this Decision. Additionally, this Decision finds that SCE's 2018-2022 demand response portfolio application complied with directives in D.16-09-056 and requested funding for demand response customer incentives. As discussed below and again in Section 8.3.2 of this Decision, SCE is directed to record all incentives in the Demand Response Program Balancing Account (DRPBA) distribution or generation sub-accounts depending on whether the program is available to all customers or bundled customers only. Then the balances shall be recorded in the Base Revenue Requirement Balancing Account (BRRBA), which will record differences between forecasted amounts and the actual incentives.

The Utilities each claim that the proposed portfolio put forth in their application aligns with the Commission's demand response goal and principles.¹⁶ PG&E asserts that the principles form the foundation of its application.¹⁷ SCE specifically states it supports the Commission's principle of market-driven demand response characterized by leveling the playing field between the Utilities and third parties and facilitating customer choice.¹⁸

The Joint Demand Response Parties and OhmConnect state that there are aspects of the Utilities' applications that are not consistent with the

¹⁶ PG&E Opening Brief, July 24, 2017, at 3-8, SDG&E Opening Brief, July 24, 2017, at 5-9, and SCE Opening Brief, July 24, 2017, at 7-8.

¹⁷ PG&E Opening Brief, July 24, 2017, at 4.

¹⁸ SCE Opening Brief, July 24, 2017, at 7-8.

Commission's goal, principles, or guidance provided in D.16-09-056 and, thus, require either modification or rejection by the Commission. Referencing the principles of demand response customer choice and market-driven demand response, the Joint Demand Response Parties maintain that disparities in demand response programs that advantage or create preferences for Utility demand response customers are not fair and do not result in a level playing between Utilities and third-party providers.¹⁹ Similarly, OhmConnect contends that certain proposals in the applications are unduly discriminatory against third party providers and their customers.²⁰ Specifically, the Joint Demand Response Parties highlight dual participation rules, and the potential for preferential treatment by the Utilities to bundled customers. Furthermore, Joint Demand Response Parties and OhmConnect also point to outreach and education funding and access to and differentiation in emerging technology incentives as examples where the Utilities' applications do not align with the principles of customer choice and market-driven demand response.

The Joint Demand Response Parties allege that the principles of customer choice and market-driven demand response require the Commission to ensure there is competitive parity between the utility-administered programs and those administered by third-parties and to correct for any undue advantages by making the same options available to third-party providers or removing the advantage.²¹ These parties point to three ways the Commission can correct

¹⁹ Joint Demand Response Parties Opening Brief, July 24, 2017, at 6.

²⁰ OhmConnect Opening Brief, July 24, 2017, at 2.

²¹ Joint Demand Response Parties Opening Brief, July 24, 2017, at 7.

Utility proposals where they allege an unfair advantage of the Utility-administered programs over third-party programs exists:

- First, arguing that the Commission should protect against a utility guiding a customer to its programs over a third-party program, the Joint Demand Response Parties and OhmConnect recommend that the Commission prohibit the Utilities from using promotional materials to solely advertise utility-administered programs.²²
- Second, the Joint Demand Response Parties contend that the Base Interruptible Program and the Capacity Bidding Program are intended to be statewide, and that divergence in program design creates difficulties for third-parties and customers that participate in these programs throughout the state.²³ Hence, the Joint Demand Response Parties request the Commission direct the Utilities to remove inconsistencies across the Base Interruptible Program and the Capacity Bidding Program in order to comply with the principle of market-driven demand response with a preference for third-party programs.²⁴
- Third, OhmConnect recommends the Commission require SCE and SDG&E to provide technology incentives to all customers and not just customers enrolled in utility-administered programs. OhmConnect argues these incentives “unfairly preference the utilities’ own demand response programs over comparable third-party demand response programs.”²⁵

In addition to these three recommendations, several parties also point to the need to review the demand response dual participation rules and the

²² *Id.* at 8.

²³ *Id.* at 9.

²⁴ *Id.* at 10.

²⁵ OhmConnect Opening Brief, July 24, 2017, at 2.

potential disparities created by these rules. This is addressed in detail in Section 6.1.2 of this Decision.

In D.16-09-056, the Commission translated the top attributes of demand response into a set of principles to guide future demand response policies and programs.²⁶ The Commission adopted the principles directing the Utilities and third-party provider to adhere to them. The principles of customer choice and market-driven demand response highlighted above are each important elements for ensuring the continued success of demand response in California. This Decision considers the reasonableness of the proposals for each demand response program and activity; the proposals described above and the concerns regarding principles of customer choice and market-driven demand response are addressed in the reasonableness discussion.

With respect to the recovery of SCE's demand response customer incentives, SCE explains that: 1) incentive revenues associated with the Base Interruptible Program, the Agricultural Pumping Interruptible program and the Summer Discount Plan are funded through surcharges embedded in the distribution rates; 2) the incentive revenues for the Save Power Day program are funded through general generation revenue imbalances; and 3) Capacity Bidding Program and Base Interruptible Program Aggregation are funded through distribution rates.²⁷ The Commission ordered the Utilities to consolidate as much as feasible all demand response program costs into the demand response application.²⁸ In D.16-06-029, the Commission found that all three Utilities are

²⁶ D.16-09-056 at 3.

²⁷ ORA-01 at Attachment 5A.

²⁸ D.12-04-045 at 42-43.

capable of consolidating demand response funding requests in the demand response application and ordered the Utilities to request funding for all programs and incentives through the application. The objective of this directive is to increase transparency, one of the principles of demand response.

SCE maintains it is in compliance with this directive because the incentives are documented in the cost-effectiveness calculation. In comments to the proposed decision, SCE explains that while it did not include incentives as budget line items, in addition to including the incentives in the cost-effectiveness calculation, SCE proposed incentive amounts in its direct testimony for each program.²⁹ Not including the incentives as budget line items led to confusion and a misunderstanding in analyzing what SCE actually requested.

This Decision finds SCE in compliance with D.16-06-029 but concludes that SCE should present future incentive proposals and amounts as budget line items in order to provide clarity and transparency and reduce confusion. SCE should record incentives in the DRPBA and use the allocation mechanisms assigned to the distribution and generation sub-accounts in that balancing account. The balances of the DRPBA should then transfer to the BRRBA. These entries will be reviewed in SCE's annual Energy Resource Recovery Account (ERRA) Compliance applications for compliance with this Decision, as well as the recovery of undercollection and distribution of overcollection.

On a final note, we recognize the Utilities had an abbreviated amount of time to develop their 2018-2022 demand response portfolio applications. To ensure ample amount of time in the future, we establish a date of

²⁹ SCE Opening Comments to Proposed Decision, November 29, 2017 at 7-8

November 1, 2021 to file 2023-2027 demand response program portfolio applications. In order to assist the Commission in a review of the applications, the Utilities are directed to meet with the Commission's Energy Division staff to discuss the contents of the applications and the format. The goal is to ensure that Energy Division has the appropriate tools to analyze the applications.

6. Reasonableness of Proposed Programs

6.1. Overarching Issues

6.1.1. Uniformity Across Programs

The Joint Demand Response Parties argue for a state-wide Base Interruptible Program and Capacity Bidding Program with uniform notification times and incentives. The Joint Demand Response Parties maintain that the principles of customer choice and market-driven demand response with a preference for third-party services require the same or similar program parameters across the Utilities. SDG&E cautions the Commission that uniformity for its own sake is not in the public interest. As further explained below, this Decision determines that given the differences between the Utilities, it is not reasonable to require the Utilities to have uniform parameters in any program required to be cost-effective, as the results could have an adverse effect on cost-effectiveness. However, the Commission encourages the Utilities to work with other interested parties to attempt to reconcile these program differences within the confines of appropriate cost-effectiveness results, prior to the 2020 demand response program update advice letter filing.

The Joint Demand Response Parties contend that uniform notification times and incentives in the Base Interruptible Program and the Capacity Bidding Program will make the programs easier for customers and third-party aggregators to understand and easier for third-party aggregators to implement,

especially statewide.³⁰ Explaining differences in operating and eligibility requirements can create confusion for customers with facilities across the state, the Joint Demand Response Parties assert that such differences also lead to higher costs for third-party providers.³¹ Joint Demand Response Parties state that those higher costs are due to: i) implementation of separate back-office capabilities to include the operating parameters of the resource for each program; ii) programming the individual criteria into software platforms; and iii) creation of different collateral and marketing tools for each program. All of these, the Joint Demand Response Parties allege, discourage third-party demand response participation in California and prevent efficient customer recruitment.³²

In response, SDG&E argues that it is not self-evident that statewide uniformity would encourage customer participation. Highlighting differences in customer base and system load curve, and the need to try different approaches, SDG&E contends that these differences produce different demand characteristics.³³ SDG&E underscores that these differences also led to the Commission rejecting the requirement for uniform time-of-use rates across the Utilities.³⁴

The Commission has, in the past and where reasonable, adopted uniform requirements for the Utilities. In D.16-06-029, the Commission adopted statewide requirements for the Auto Demand Response program. However, the

³⁰ Joint Demand Response Parties Opening Brief, July 24, 2017, at 11 and 24.

³¹ Joint Demand Response Parties Opening Brief, July 24, 2017, at 9.

³² Joint Demand Response Parties Opening Brief, July 24, 2017, at 9-10.

³³ SDG&E Reply Brief, August 4, 2017, at 8-9.

³⁴ SDG&E Reply Brief, August 4, 2017, at 9-10.

Auto Demand Response program does not require cost-effectiveness analyses and therefore the differences in customer base and system load curve do not have as great of an impact as they would on a program required to be cost-effective. The Commission previously found that marginal costs and load shapes differ across the three Utilities.³⁵ Different marginal costs and load shapes can require different parameters to be implemented across the Utilities for the same program in order for a program to be cost-effective. Hence, this Decision concludes the Commission should not require uniform parameters for any demand response program required to be cost-effective, including the Base Interruptible or the Capacity Bidding Programs. That being said, the Utilities are directed to work with interested parties to see if there are parameters that can be uniform across the three Utilities, while ensuring that cost-effectiveness results remain acceptable. The Utilities shall report on the discussions and the results of the efforts in their 2020 program update filing.

6.1.2. Dual Participation

The Commission created the dual participation rules to allow customers to simultaneously participate in two demand response programs while ensuring that customers do not receive two payments for the same load reduction.³⁶ The Commission adopted three rules, first in D.09-08-027 and then confirmed in D.12-04-045: 1) Duplicative payments for a single instance of load reduction or load drop is prohibited;³⁷ 2) dual participation is permitted in two demand

³⁵ SDG&E Reply Brief, August 4, 2017, at 10 citing D.17-01-006 at 31.

³⁶ D.12-04-045 at 47-48.

³⁷ In the case of simultaneous or overlapping events called in two programs, a single customer enrolled in those two programs shall receive payment only under the capacity program, not for the energy payment programs.

response activities, if one provides an energy payment and the other provides capacity payments; and 3) dual participation in two day-ahead or two day-of programs is prohibited.³⁸ Furthermore, Electric Rule 24/32 prohibits customers from simultaneously participating in a program provided by a third-party and bid into the CAISO market and an event-based utility-administered demand response program.³⁹

The Joint Demand Response Parties point to a CAISO rule requiring one demand response provider per customer contending that it results in a disadvantage to third-party providers; Joint Demand Response Parties make the same contention about the Commission rule prohibiting simultaneous participation in the auction mechanism and a utility-administered demand response program. The Joint Demand Response Parties note, however, that utility customers enrolled in a supply side program, which is bid into the CAISO market, *e.g.*, Base Interruptible Program, can be dually enrolled in Peak Day Pricing, which is a utility program.

The Joint Demand Response Parties focus specifically on the issue of enrollment by a customer in the demand response auction mechanism and state that because of the CAISO limitation of one demand response provider per customer, the customer enrolled in a demand response program through the demand response auction mechanism cannot be enrolled in a utility program. Joint Demand Response Parties explain that customer registrations in the CAISO system are being rejected if customers are dually enrolled in a third-party program and a utility program and the third-party demand response providers

³⁸ D.12-04-045 at Section 6.3.

³⁹ See, for example, PG&E Tariff Electric Rule 24 at C.2.d.

must manually unenroll the customer from active participation in a utility program. In addition to an unlevel playing field, the Joint Demand Response Parties maintain this also creates an undue burden on the third-party provider and the customer, especially for mass market programs whose customers are accustomed to digital processes.⁴⁰ The Joint Demand Response Parties request the Commission reexamine the dual participation rules and allow third-party customers to dually participate on a comparable level to Utilities' customers also enrolled in wholesale market programs.⁴¹

In response, PG&E supports such a re-examination but cautions that dual participation rules exist for a number of reasons that appear insurmountable within the current rules. PG&E explains that those reasons include: avoiding conflicting signals due to multiple dispatches for the same intervals for the same capacity, ensuring accurate baseline calculations, as well as avoiding double payments.⁴²

First, conflicting policy statements have led to confusion about the dual participation rules. In D.12-11-025, the Commission prohibited the enrollment of a customer in a demand response provider service where the load is bid into the CAISO energy market if that customer is already enrolled in a Utility *event-based* (emphasis added) demand response program.⁴³ D.12-11-025 identified Critical Peak Pricing and Peak Day Pricing programs as event-based programs.

⁴⁰ Joint Demand Response Parties Opening Brief, July 24, 2017, at 19.

⁴¹ *Id.* at 20.

⁴² PG&E Reply Brief, August 4, 2017, at 8-9.

⁴³ D.09-08-027 at 155, D.10-02-032 at 58, and D.12-04-045 at 54-55 affirmed Critical Peak Pricing and Peak Day Pricing as energy based programs for purposes of dual participation.

D.13-12-029 and Resolution E-4630 continued the designation of Critical Peak Pricing and Peak Day Pricing as event-based demand response programs. However, in D.15-11-042, the Commission stated that non-event based load modifying programs include Critical Peak Pricing, Real Time Pricing, time of use rates, Permanent Load Shifting and Peak Day Pricing.⁴⁴ This Decision finds that there are differing views with respect to whether Critical Peak Pricing and Peak Day Pricing are non-event based load modifying programs but concludes that the record is insufficient for the Commission to revise its policies on dual participation in a third-party demand response program and a utility administered demand response program.

Secondly, a statement in D.12-11-025 has led parties to believe that CAISO prohibits registered customers from participating in any other demand response program or having more than one demand response provider. However, D.13-12-029 modified Ordering Paragraph 7 of D.12-11-025 as follows:

“Demand response providers are prohibited from placing a customer account into a resource registration in the CAISO Demand Response System for any time period within the Start Date and End Date of another demand response provider’s resource registration if that account has been given a “Confirmed” status by the CAISO under its rules and procedures.”

This modification clarifies that CAISO limits customers to one Scheduling Coordinator (*see* Tariff Section 4.5.1.1.3) and prohibits registration of a location to both a Reliability Demand Response Resource and a Proxy Demand Resource for the same trading day (*see* Tariff Section 4.13.1). CAISO also limits customers to one load serving entity. Therefore, the Joint Demand Response Parties concern

⁴⁴ D.15-11-042 at 16-17.

regarding one demand response provider is moot with respect to bundled customers.⁴⁵

With respect to unbundled customers, D.10-06-002 requires that Direct Access customers enrolled in a utility-administered demand response program withdraw from the utility program before engaging in direct bidding to the CAISO wholesale electric markets through a third party.⁴⁶ Neither D.13-12-029 nor D.12-11-025 revised this guidance. Therefore, any unbundled customer wanting to participate in energy rates (*e.g.*, Critical Peak Pricing or Peak Day Pricing) may only participate in this type of rates through their load serving entity.

In order to supplement the record on the dual participation issue and provide clarity on dual participation rules, a workshop will be held and facilitated by the Administrative Law Judges in early 2018. A final determination on this issue will be addressed in a future decision in this proceeding.

⁴⁵ Bundled customers are defined as customers who receive generation and distribution services from one of the Utilities. Unbundled customers only receive distribution services from one of the Utilities and receive generation from another load serving entity.

⁴⁶ D.10-06-002 at Ordering Paragraph 4.

6.2. Load Modifying Demand Response Programs

Load modifying programs are defined as resources that reshape or reduce the net load curve. Furthermore, a load modifying program must be embedded into the California Energy Commission's unmanaged/base case load forecast.

6.2.1. Optional Binding Mandatory Curtailment Program, Rotating Outages Program, and Scheduled Load Reduction Program⁴⁷

The Optional Binding Mandatory Curtailment Program exempts qualifying customers from rotating outages in return for a partial load reduction. The Scheduled Load Reduction Program is subject to Public Utilities Code Section 740.10 and cannot be closed without legislation. The Rotating Outages program is also statutorily required but, as discussed below, is not a demand response program. Beginning in 2023, funding requests for the Rotating Outages program should be included in general rate case applications.

6.2.1.1. PG&E

PG&E states that the Optional Binding Mandatory Curtailment Program is fully subscribed and is not proposing any changes to this program for the 2018-2022 budget cycle. PG&E also reports that its Scheduled Load Reduction Program has no customers and is capped at zero MWs pursuant to D.09-08-027.

⁴⁷ Programs are combined here because PG&E has requested a single budget for the Optional Binding Mandatory Curtailment Program and the Scheduled Load Reduction Program.

PG&E requests \$63,095 for the Optional Binding Mandatory Curtailment Program and the Scheduled Load Reduction Program, as shown in Table 5.⁴⁸ The Commission authorized \$41,842 for the Optional Binding Mandatory Curtailment Program and the Scheduled Load Reduction Program in D.16-06-029 for the 2017 bridge year. Because PG&E is not proposing any changes to these programs, there is no opposition to the current programs, and the annual requested budget is less than the 2017 budget, we find PG&E's request reasonable and authorize the requested budget for the Optional Binding Mandatory Curtailment and the Scheduled Load Reduction Programs.

Table 5 PG&E's Budget Request for the Optional Binding Mandatory Curtailment Program and the Scheduled Load Reduction Program						
	2018	2019	2020	2021	2022	Total
OMBC/SLRP	\$11,784	\$12,231	\$12,620	\$13,022	\$13,437	\$63,095

6.2.1.2. SCE

SCE's proposal for its Optional Binding Mandatory Curtailment Program and the associated budget are approved. SCE proposes to eliminate the one-year term and written renewal requirement from the agreement removing an unnecessary administrative task. SCE also proposes to eliminate the dedicated phone requirement. Noting there have been no new enrollments in this program since 2009, SCE requests funding to modify program documentation, fact sheets and reminders, as well as notification costs. No party opposes the proposal or budget requests. The proposal and budget are reasonable and should be

⁴⁸ PG&E Application at 15.

approved. SCE is authorized a five-year budget of \$15,000 for the Optional Binding Mandatory Curtailment Program.

SCE's proposal for its Rotating Outages program and the associated budget are approved. SCE expects the programs, policies and procedures to continue and be actively maintained. However, SCE asserts this is not a demand response program and should be removed from future demand response portfolio applications. SCE recommends that the funding be requested in its general rate cases. SCE requests a five year budget of \$400,000 to maintain the program. No party opposes the recommendation or the budget request.

For the past three years, the Commission has been working toward ensuring the demand response portfolios are accurately portraying the demand response programs. The Rotating Outages program is not a demand response program and should not be included in the demand response portfolio. This Decision authorizes the five-year budget for the Rotating Outages program and requires the Utilities to include any future requests for this program in their respective general rate case applications.

SCE's proposal and budget for its Scheduled Load Reduction Program are adopted. This statewide legislated program is offered to SCE customers with an average monthly demand of greater than 100 kW. No customers have enrolled in the program since 2010, but the Commission has no authority to close the program because the Scheduled Load Reduction Program is legislatively mandated.⁴⁹ SCE proposes to continue the program with no modifications and requests a budget of \$15,625. No party opposes SCE's proposal or requested

⁴⁹ Public Utilities Code Section 740.10.

budget. SCE proposes no changes since the Commission last approved this program and has proposed a slightly lower annual budget than in 2017. SCE's proposal and associated budget are reasonable and should be adopted. SCE is authorized a five-year budget of \$15,625 for the Scheduled Load Reduction program.

6.2.2. Critical Peak Pricing Programs

6.2.2.1. PG&E

PG&E's load modifying programs, Peak Day Pricing and Smart Rate, are not addressed in the Motion of the Settling Parties. According to PG&E, both programs provide for increased charges for usage during event hours and reduced charges during non-event hours. While the Peak Day Pricing target non-residential bundled-service customers, the SmartRate Program is offered to residential bundled-service customers. Both programs' administration costs are typically approved in GRC proceedings, but PG&E requests funding in this proceeding to cover measurement and evaluation costs amounting to \$500,000.⁵⁰ PG&E plans to transition these costs to the general rate cases starting in 2020.⁵¹ PG&E's request is unopposed. We approve PG&E's budget request to cover measurement and evaluation costs of Critical Peak Pricing Programs until 2020.

⁵⁰ PGE-06, Chapter 6, Budget Workpaper at 2018-22 EM&V DirectAssign.

⁵¹ PGE-01 at 2-12.

6.2.2.2. SDG&E

SDG&E asserts that as time-of-use rate offerings increase, the need for the Peak Time Rebate program decreases. SDG&E requests a budget of \$21,771 to maintain and support the Peak Time Rebate program as it ramps down. No party opposes this request. Retaining the Peak Time Rebate program would duplicate the efforts of time-of-use rates. Hence, SDG&E's request to end its Peak Time Rebate program is granted. However, as discussed in Section 7.2.3, SDG&E's administrative budget is reduced by 10 percent to assist in improving the cost-effectiveness of the program. SDG&E is authorized a budget of \$19,594 for program year 2018 only.

6.3. Supply Side Demand Response (Reliability Programs)

Supply side demand response programs are defined as resources that are integrated and bid into the CAISO energy market. Reliability programs are those that are triggered in response to an actual or imminent declaration by CAISO of a system emergency. Supply side demand response programs include the Base Interruptible Program and the Agricultural Pumping Interruptible Program.

6.3.1. Issues Regarding the Reliability Cap

This Decision establishes two processes for addressing issues regarding the two percent reliability cap. First, the Director of the Energy Division is authorized to hold a workshop before February 15, 2018 for parties to develop a consensus proposal for prioritizing resources under the current two percent reliability cap. No later than March 30, 2018, the Utilities shall file a consensus proposal recommending the manner in which the Commission should prioritize resources under the cap. Second, this Decision assigns the review of the reliability cap to the Supply Side Working Group established in D.17-10-017. As

described below, the working group shall file a report on its progress in this matter, in this proceeding, no later than March 30, 2018. Parties shall file comments on both the prioritization proposal and the reliability cap report no later than April 14, 2018.

In D.10-06-034, the Commission adopted a settlement agreement that, among other things, established a two percent cap on the amount of reliability demand response that would count toward a utility's resource adequacy obligation requirement. According to the settlement, the cap could be revised after 2015. Parties to the settlement also agreed that any re-consideration of the two percent cap would benefit from several inputs.⁵² In D.16-06-029, the Commission determined that it is not necessary to suspend the cap, but suggested that the cap could be reviewed and stated the issue may require evidentiary hearings in the future.

In testimony, the Joint Demand Response Parties and ORA request the Commission readdress the cap based on two concerns: 1) the potential for insufficient room for resources under the cap; and 2) the fairness of the current prioritization method for addressing allocation of the available capacity under the cap. ORA contends reaching the cap is a future issue but should be addressed no later than the mid-cycle review. However, ORA asserts the issue may be moot if the auction mechanism is not adopted permanently following the evaluation of the Pilot and adds that increasing the cap now is premature.

⁵² D.10-06-034, Appendix A, at 10 at Number 6.

The Joint Demand Response Parties maintain that a proposal made by PG&E to use a five-tier hierarchy⁵³ to address allocation of the available capacity is harmful to third-party demand response providers. The hierarchy allows the Utilities to provide preferential access for its customers to the available capacity under the cap. Joint Demand Response Parties assert this treatment could foreclose third-party providers from providing similar services to its customers on a comparable basis that is eligible for resource adequacy credit.⁵⁴

PG&E's cap was reached in late 2016 and now has a waitlist for prospective Base Interruptible Program customers.⁵⁵ As part of the Settlement between PG&E and the Joint Demand Response Parties, the reliability cap approved in D.10-06-034 is maintained. The Settlement recommends a collaborative process under the oversight of the Energy Division to begin during the first quarter of 2018.⁵⁶ The collaborative process would address the management of the megawatts under the cap.

SCE's reliability demand response is 625 MW, only slightly below its current cap of 659 MW. SCE cautions that it expects to reach or exceed its cap

⁵³ The hierarchy would allocate available capacity to 1) PG&E's Base Interruptible Program; 2) third-party demand response providers selected in the third Auction Pilot who already have capacity through the second Auction Pilot; 3) Base Interruptible Program wait listed customers; 4) the second Auction Pilot participants who had increased their Reliability Demand Response Resource commitment from 2017 to 2018 and 2019; and 5) New Auction Pilot Reliability Demand Response Resource customers. (See JDP-01 at 32.)

⁵⁴ Joint Demand Response Parties Opening Brief, July 24, 2017, at 17.

⁵⁵ ORA-02 at Attachment 6-A.

⁵⁶ Motion for Settlement at 3; and Settlement Agreement at 7.

shortly.⁵⁷ SCE states that while a “first-come, first-served” approach to receiving capacity value is reasonable, it creates administrative questions such as if a bid is deemed above the reliability cap should it be placed on a wait list.⁵⁸ SCE recommends the Commission review whether an increase in the reliability cap is warranted.⁵⁹

SDG&E takes no position on this issue, highlighting that it has a large percentage of its 16 MW reliability cap available.⁶⁰

The record shows that managing the megawatts under the cap should be addressed in the very near future, as PG&E has already reached the reliability cap and SCE is close to reaching the cap. In the Settlement, PG&E and the Joint Demand Response Parties recommend a collaborative process for managing the reliability cap with the Energy Division facilitating the process. This process is reasonable. The Director of the Energy Division is authorized to hold a workshop no later than February 15, 2018 to begin discussions on managing the reliability cap and prioritizing resources under the current two percent reliability cap. Every party shall provide a proposal for managing the current reliability cap at the first meeting of the working group; joint proposals are encouraged. Parties should then work toward a consensus proposal, and if reached, a consensus proposal may be filed in this proceeding by the Utilities on behalf of the workshop participants. Alternatively, if a consensus is not reached, the Utilities, on behalf of the workshop participants, shall file a report on the

⁵⁷ SCE-01 at 14.

⁵⁸ *Id.* at 14-15.

⁵⁹ *Id.* at 15.

⁶⁰ SDG&E Opening Brief, July 24, 2017, at 18.

workshop discussions and include all proposals along with support and opposition. The Utilities shall file either the consensus proposal or the workshop report no later than March 30, 2018; comments on the proposal or report shall be filed no later than April 14, 2018.

Developing a proposal for managing the current reliability cap is a short term goal; determining whether the Commission should maintain the current two percent cap should be a longer term goal but may require an evidentiary hearing as determined earlier by the Commission. D.17-10-017 establishes a Supply Side Working Group. Because reliability programs are now bid into the CAISO market as a supply resource, this Decision adds the issue of reviewing the two percent cap to the tasks of that working group. The Supply Side Working Group shall consider the inputs agreed to in D.10-06-034.⁶¹ The working group shall file a report on the status of the working group's discussions and/or resolutions with respect to this issue. The report shall be filed in this proceeding no later than March 30, 2018. If the working group determines an evidentiary hearing is necessary, the report should request the hearing. If more time is needed, the working group should indicate the amount of time required and a proposed regulatory process for approving its process. Comments on the report may be filed no later than April 14, 2018.

6.3.2. Agricultural Pumping Interruptible Program

6.3.2.1. SCE

SCE proposes several new changes for the Agricultural Pumping Interruptible program including the introduction of a firm service level option,

⁶¹ D.10-06-034 at Appendix A, Section C.6., page 10.

excess energy charges, and an automatic firm service level adjustment for direct load control devices. SCE also proposes to require program customers to enroll in a time-of-use rate schedule, replace remotely alterable addressing devices with Corporate Systems Engineering devices for consistency, and update incentives for the program. No party opposes the changes to or the proposed incentives for the Agricultural Pumping Interruptible program. SCE's requested revisions to the program, including the proposed incentives, are reasonable and are adopted. SCE is authorized a budget of \$3.34 million for the Agricultural Pumping program and an incentive budget cap of \$32 million.

6.3.3. Base Interruptible Program

As described below, this Decision adopts proposal for each of the three Utilities' Base Interruptible Programs, whereby enrolled customers receive an incentive either from the utility or an aggregator for reducing load to a pre-determined Firm Service Level either when there is an emergency condition as defined by the CAISO or a transmission contingency.⁶² Within 30 days from the issuance of this Decision, the Utilities shall file Tier One Advice Letters updating their Base Interruptible Program tariff to comply with this Decision.

In comments to the proposed decision, CLECA indicates that SCE and PG&E's tariff for the Base Interruptible Program provides a one-month "window" between November 1 and December 1 whereby customers may revise their Firm Service Levels. CLECA request that customers be provided additional windows of time following the issuance of a final decision in this proceeding to revise their Firm Service Levels since the tariff window has passed. The request is reasonable. The Utilities shall include a revised window for the 2018 program

⁶² PGE-01 at 2-1.

year in the required advice letter updating their Base Interruptible Program tariffs.

6.3.3.1. PG&E

PG&E currently offers a Base Interruptible Program, which is available to its bundled-service, Community Choice Aggregation, and Direct Access commercial, industrial, and agricultural customers, on a year-round basis.⁶³ The Settlement discussed in Section 4 addresses a number of PG&E's proposals regarding this program, including credit and collateral issues and time periods used to calculate incentives.

According to the Settlement, (1) PG&E will withdraw its proposal to add credit and collateral provisions, but retain the discretion to submit a proposal in an appropriate Commission venue, *e.g.* mid-cycle review; (2) pursuant to CLECA's proposal to modify time periods used to calculate incentives for Base Interruptible Program, PG&E will synchronize these periods with time-of-use periods when time-of-use periods are adopted in PG&E's GRC Phase 2 or Rate Design Window proceeding.⁶⁴ PG&E will also conduct a pilot program for bidding a small number of Base Interruptible Program megawatts into the CAISO market on a day-ahead basis. The goal of the pilot is to improve understanding of bidding and settlement across day-ahead and real-time markets.⁶⁵ After the pilot, PG&E will consult with the parties on the pilot results and possible expansion. If the pilot is determined to be successful, PG&E's proposal for a day-ahead option to be available to all Base Interruptible Program

⁶³ PGE-01 at 2-2.

⁶⁴ CLC-01 at 15.

⁶⁵ Settlement Agreement at 6.

customers will be filed in an advice letter. PG&E anticipates that a permanent program may be set in place by end of 2018.

PG&E also proposes to increase the maximum event duration from four hours to six hours, arguing that this will align PG&E's program with other Utilities' programs and help PG&E meet the needs of the grid.⁶⁶ In order to support its proposal, PG&E presents the weighted loss of load expectation heat map from the E3's Renewable Energy Capacity Planning (RECAP)⁶⁷ model and concludes that a resource that can operate for six hours during an event benefits the system more than a resource that operates for four hours.⁶⁸ PG&E argues that by extending the maximum Base Interruptible Program event duration to six hours, the Base Interruptible Program can more effectively address system outages when they are most likely to occur.⁶⁹

PG&E requests \$161.770 million for the Base Interruptible Program, as shown in Table 6 below:

Table 6						
PG&E's Budget Request for Base Interruptible Program (in thousands)						
Program Year	2018	2019	2020	2021	2022	Total
Program Budget	\$ 566	\$ 566	\$ 566	\$ 566	\$ 566	\$ 2,832
Incentives	\$ 31,788	\$ 31,788	\$ 31,788	\$ 31,788	\$ 31,788	\$ 158,938
Total	\$32,354	\$32,354	\$32,354	\$32,354	\$32,354	\$161,770

⁶⁶ PGE-01 at 2-3.

⁶⁷ D.16-06-007 Ordering Paragraph 4 adopted the RECAP model for hourly time-allocation of avoided generation capacity costs to be used across all Commission proceedings.

⁶⁸ PGE-01 at 2-3.

⁶⁹ PGE-01 at 2-4.

The Commission authorized \$257,725 for PG&E's Base Interruptible Program in D.16-06-029 for the 2017 bridge year. PG&E attributes the large difference between its requested annual budget for 2018-2022 and the authorized budget for 2017 to the Commission's direction in D.16-06-029 for the Utilities to consolidate demand response spending into their demand response applications, leading to Base Interruptible Program incentives of \$31.79 million annually to be included in this application.⁷⁰ If the Base Interruptible Program incentives were excluded, the requested funds for Base Interruptible Program (as well as the Optional Binding Mandatory Curtailment and the Scheduled Load Reduction programs) would be \$309,000 more annually than what was authorized in 2017.⁷¹ PG&E attributes this difference to higher Base Interruptible Program administration costs associated with managing a CAISO integrated resource.⁷²

PG&E's proposals related to the Base Interruptible Program have been addressed in the Settlement, which we have determined to be in the public interest. Furthermore, the requested budget, excluding the incentives, is close to the authorized cap. Therefore, we find PG&E's request reasonable and authorize a total budget of \$161.77 million and an incentive cap of \$31.79 million annually.

6.3.3.2. SCE

SCE proposes several changes to the Base Interruptible Program. The major contested changes include: 1) elimination of account aggregation in its Base Interruptible Program for lack of interest and to save costs, and 2) valuing the 15-minute and 30-minute notification times differently in order to account for

⁷⁰ PGE-01 at 6-10.

⁷¹ PGE-01 at 6-10 and PGE-08 at 3.

⁷² PGE-01 at 6-10.

the avoided cost of having to procure local resource adequacy for the 15-minute option and to reflect the CAISO rules for local capacity resources.⁷³ SCE notes that if the Commission rejects its request to eliminate the aggregator option, SCE must modify the current rules to “bring the tariff up to date with CAISO market integration requirements, current technology, and SCE’s billing and settlement systems.”⁷⁴ These proposed changes are in addition to SCE’s proposal to use the Avoided Cost Methodology to determine program incentives for 2018 to 2022.⁷⁵ In comments to the proposed decision, CLECA highlights that the incentive proposal will reduce Base Interruptible Program incentives by three percent.⁷⁶ SCE confirms that the incentives will be reduced by three percent.⁷⁷

Joint Demand Response Parties underscore that the Commission rejected SCE’s request to eliminate the aggregator option in D.16-06-029, noting that there was no data to support SCE’s claim that the elimination would save costs. Given the elimination of the Aggregator Managed Portfolio contracts, Joint Demand Response Parties indicate there is renewed interest in the aggregator option, and highlight SCE’s statements during the evidentiary hearing regarding the increased interest in the aggregator option that could lead to the reliability cap

⁷³ SCE Opening Brief, July 24, 2017, at 14 and SCE-03 at 8.

⁷⁴ SCE-02 at 12.

⁷⁵ SCE-03 at 2. SCE explains that the Avoided Cost Methodology uses the “A times B” Methodology whereby the avoided generation capacity value is adjusted through the use of the A and B factors that compare the program resource value to a proxy combustion turbine resource.

⁷⁶ CLECA Opening Comments to Proposed Decision, November 29, 2017 at 4-5.

⁷⁷ SCE Reply Comments to Proposed Decision, December 4, 2017 at 2-3.

being reached or exceeded.⁷⁸ The Joint Demand Response Parties allege that elimination of the aggregator option would result in SCE having a preferential treatment for declining capacity under the reliability cap.⁷⁹ Furthermore, Joint Demand Response Parties contend that the proposed tariff changes requested by SCE (if the Commission does not grant the request to eliminate the aggregator option) are akin to eliminating the aggregator option because the tariff changes require smaller disaggregation. SCE maintains that the tariff changes are necessary in order to ensure that all resources from the Base Interruptible Program can be integrated and used for both CAISO system and local distribution emergencies.

SCE is directed to continue the aggregator option in its Base Interruptible Program. The record shows that there is increased interest in participating in this option, which provides another participation option to aggregators. The benefits of maintaining this option outweigh the low costs of SCE providing the option.

Furthermore, SCE is authorized to submit its other proposed changes to the tariff through a Tier two advice letter process. While the Joint Demand Response Parties argue that the proposed tariff change to a smaller disaggregation is more difficult for aggregators to manage, SCE explains that dispatching at the Load Zone (also known as the A Bank) level allows SCE to combine both directly enrolled resources and aggregated resources that co-exist in the same load zones into the same CAISO resource identifications for bidding

⁷⁸ Joint Demand Response Parties Opening Brief, July 24, 2017, at 13, citing Transcript) TR at 37-38 and 46-48.

⁷⁹ *Id.* at 13.

into the CAISO.⁸⁰ Hence, the proposal to allow individual service accounts and individual firm service levels and dispatch events by load zones will assist SCE in decreasing the number of megawatts not able to be integrated into the CAISO market. This decision finds the proposed tariff change reasonable because it improves integration into the CAISO market. However, SCE shall continue to settle based on aggregated firm service levels, albeit smaller aggregations, rather than individual firm service levels. As pointed out by the Joint Demand Response Parties in comments to the proposed decision, if performance is based on the individual firm service load, it would essentially eliminate the aggregator option.⁸¹

SCE is authorized to file a Tier Two Advice Letter requesting the changes, no later than 30 days from the issuance of this Decision; this will allow the Commission and parties the opportunity to review and respond to SCE's proposal. The advice letter shall include a detail explanation of SCE's proposal to combine directly enrolled and aggregated resources. The Commission's expectation of this proposal is to allow smaller aggregations but not complete disaggregation. Hence, while we allow individual firm service levels, we do so only to enable SCE to combine both directly enrolled resources and aggregated resources that co-exist in the same load zones into the same CAISO resource identifications." The Joint Demand Response Parties oppose SCE's proposal to value the 15-minute and 30-minute notification options differently, arguing that the proposal is based on a suspended CAISO proposal that has not been

⁸⁰ SCE Reply Brief, August 4, 2017, at 5.

⁸¹ Joint Demand Response Parties Opening Comments to Proposed Decision, November 29, 2017 at 7.

adopted. SCE proposes to adjust the current incentives to account for the avoided cost of having to procure local resource adequacy for the 15-minute option. Specifically, SCE proposes to increase by 10 percent the incentive for the 15-minute option and decrease by 3 percent the 30-minute option. SCE explains that the “asymmetric adjustment between the programs is due to the larger amount of expected demand available under the 30-minute option in comparison to the 15-minute option.”⁸²

Because the Commission in the Resource Adequacy proceeding has not implemented the requirement for resources to be subject to a 20-minute notification requirement in order to qualify as local resource adequacy capacity, it is premature for the Commission to adopt SCE’s proposed new valuation to the 15-minute option in this proceeding and, accordingly, the associated changes to the 30-minute option. However, should the Commission in the Resource Adequacy proceeding adopt the 20-minute notification requirement, SCE is authorized to file a Tier 2 advice letter requesting approval for the proposed tariff changes. The Tier 2 Advice Letter will allow further review and input by the parties and Commission Staff.

This Decision authorizes SCE a budget of \$1.697 million to administer its Base Interruptible Program and an incentive cap of \$345.776 million.

In comments to the proposed decision, CLECA requests the Commission acknowledge a stipulation between SCE and CLECA whereby SCE agrees to explore the creation of a Day-Ahead energy-based demand response program to replace the now defunct Demand Bidding Program and enable Base Interruptible

⁸² SCE-03 at 8.

Program customers to dually participate in both programs.⁸³ CLECA highlights that pursuant to D.10-06-034, if a customer dually participates in an energy-based program and a reliability program, the load reduction does not count toward the two percent reliability cap.⁸⁴

6.3.3.3. SDG&E

SDG&E proposes two major changes to its Base Interruptible Program: 1) reducing customer incentives by 10 percent, and 2) revising hours from 11:00 a.m. to 6:00 p.m. to align with the hours used in resource adequacy, 1:00 p.m. to 6:00 p.m. SDG&E contends the intention of the reduced incentive is to improve cost-effectiveness while the revised hours should better reflect the value of the load shed and align customer payment with load reduction, thus, benefitting ratepayers.⁸⁵

Joint Demand Response Parties argue that the 10 percent reduction is not supported since appropriate incentives remain a key basis for encouraging customer participation. However, both ORA and UCAN argue for further cost reductions to SDG&E's programs to improve cost-effectiveness; the Base Interruptible Program has a total resource cost test result of 0.8. A cost-effective program should achieve a result of 1.0. Improving cost-effectiveness is a reasonable basis for a reduction in the program incentive. The need to provide appropriate incentives must be balanced with the statutory requirement that demand response be cost-effective. The issue of SDG&E's cost-effectiveness

⁸³ CLECA Opening Comments to Proposed Decision, November 29, 2017 at 5-7. (See also SCE Reply Comments to Proposed Decision, December 4, 2017 at 3.)

⁸⁴ *Id.* at 6 citing CLC-01 at 16 and 19.

⁸⁵ SDG&E Opening Brief, July 24, 2017, at 17 and TR at 182-183.

results is discussed in greater detail in section 7.2.3 below. The 10 percent reduction in incentives is reasonable given the need to improve cost-effectiveness.

Furthermore, this Decision grants the request to revise the hours to those used in resource adequacy. Joint Demand Responses Parties contest the change in hours because the hours differ from the hours in the PG&E and SCE Base Interruptible Program. This Decision has determined that uniformity of hours between the Utilities is not a requirement. Hence, SDG&E may change the hours for the Base Interruptible Program to 1:00 p.m. to 6:00 p.m.

SDG&E's Base Interruptible Program is reasonable as described herein and should be adopted. However, this Decision also reduces SDG&E's administrative budget by an additional 10 percent to assist in improving the cost-effectiveness of this program. SDG&E is authorized a five-year budget of \$4.6644 million.

6.4. Supply Side demand Response (Price Responsive Programs)

Price responsive programs address spikes in wholesale market prices by providing customers with pricing incentives. Price responsive programs are triggered based on the wholesale market prices or when system conditions warrant and include Air Conditioning Programs and the Capacity Bidding Program.

6.4.1. Air Conditioning Programs

The following sections present a review of each of the Utilities' air conditioning programs. Within 30 days of the issuance of this Decision, each Utility is directed to file a Tier 1 Advice Letter updating its air conditioning program tariff to comply with this Decision, as discussed below.6.4.1.1. PG&E

PG&E's SmartAC program is an air conditioning direct load control program for residential customers, operated from May 1 through October 31. PG&E proposes to continue SmartAC program as approved in D.16-06-029 and requests \$31.98 million for 2018-2022.⁸⁶ No party opposes this request. PG&E's proposal for the SmartAC program is reasonable and should be adopted. We authorize PG&E's budget request.

Table 7 PG&E's Budget Request for the SmartAC Program						
Program year	2018	2019	2020	2021	2022	Total
(in thousands)	\$ 6,396	\$ 6,396	\$ 6,396	\$ 6,396	\$ 6,396	\$ 31,978

6.4.1.2. SDG&E

Formerly known as the Summer Saver program, SDG&E's AC Saver Program currently utilizes direct load control switches to decrease load from residential and commercial customers' air conditioning units. In 2017, SDG&E began to transition the program to be partially bid into the CAISO wholesale market; commercial customers not dually participating in a critical peak pricing rate were bid into the market in 2017. In 2018, SDG&E proposes that as the direct load control switches age and need to be replaced, SDG&E will extend eligibility in the program to other devices capable of curtailing air conditioner use, including thermostats, fully integrated home security and alarm systems, and whole home energy management systems. SDG&E highlights this is in compliance with the principle of technology neutral demand response. SDG&E also proposes a "bring your own device" option to the AC Saver program.

⁸⁶ PGE-01 at 6-10 and PGE-08 at 3.

SDG&E requests other related changes. For commercial customers who obtained technology through the Small Customer Technology Deployment program and are not enrolled in a Critical Peak Pricing rate, SDG&E proposes to transition these customers into the AC Saver program in 2018. Residential customers with technology obtained through the Small Customer Technology Deployment program will be automatically enrolled in the AC Saver program in 2018. To successfully integrate air conditioner curtailing technology into the AC Saver Program, SDG&E plans to offer a day-ahead and a day-of option. To encourage residential participation in both options, SDG&E proposes to offer an annual capacity payment. Commercial customers will be offered an annual capacity payment for participating in the day-of option. Although the Commission recently adopted a revised trigger for this program, SDG&E proposes a variable price responsive heat rate trigger to be used beginning in 2018. SDG&E requests a budget of \$12.312 million for the five-year program cycle.

The Joint Demand Response Parties support SDG&E's request to transition the AC Saver Program to a "bring your own device" program while simultaneously allowing existing customers with direct control switches to continue to participate in the program. The Joint Demand Response Parties contend the proposal should improve customer satisfaction, increase program enrollment, reduce program attrition and minimize costs.⁸⁷

This Decision finds that allowing a transition to other devices including the "bring your own device" option in the AC Saver program without

⁸⁷ Joint Demand Response Parties Opening Brief, July 24, 2017, at 22.

abandoning the currently used devices is a prudent approach to using ratepayer funds and should minimize costs. As highlighted by SDG&E, the expected life cycle of the current direct control devices is about 20 years.⁸⁸ Additionally, this Decision agrees that offering additional options should improve customer satisfaction and increase enrollment. The changes proposed by SDG&E for its AC Saver program are reasonable and should be adopted. However, SDG&E's cost-effectiveness results for this program are less than desirable. As discussed in section 7.2.3, the Commission decreases SDG&E's administrative costs by 10 percent in order to improve the cost-effectiveness of this program. Hence, SDG&E is authorized a budget of \$11.89 million over the five-year program cycle.

6.4.1.3. SCE

Although SCE's Peak Time Rebate program is not in and of itself an air conditioning program, it is addressed here with the Summer Discount Plan because of SCE's future plans, as described below.

SCE's Summer Discount Plan uses radio frequency load switches to periodically turn off or cycle off a residential or commercial customer's air conditioner compressor during periods of peak energy demand, system emergencies, or times of high wholesale energy prices, in return for a bill credit from June 1 to October 1. For the 2018-2022 program cycle, SCE recommends efforts that focus on program maintenance, switch replacement, and event management. SCE proposes to continue the Summer Discount Plan program until the Peak Time Rebate program has enrolled enough customers and capacity and is a viable option to replace the Summer Discount Plan program. The most

⁸⁸ SDG&E Opening Brief, July 24, 2017, at 20.

notable change that SCE proposes to the Summer Discount Plan is a reduction in requested incentive funding of nearly 50 percent due to a reduction in demand and reduced incentive levels.⁸⁹ SCE requests a five-year budget of \$37.680 million and incentives of \$182.378 million for the summer Discount Plan; SCE also requests a five-year budget of \$8 million and incentives of \$12.4 million for the Peak Time Rebate program.⁹⁰

The Joint Demand Response Parties urge the Commission to direct SCE to reduce future investment in this program and transition those funds to a “bring your own device” program similar to SCE’s Peak Time Rebate program. According to the Joint Demand Response Parties, the increase in attrition and the large numbers of customers currently in the Summer Discount Plan warrant the transition.⁹¹ Pointing to the Peak Time Rebate program as an example, the Joint Demand Response Parties predict that as a “bring your own device” program scales, its reliability, consistence and overall impact increases.⁹² In response, SCE argues that it already has a “bring your own device” program, *i.e.*, the Peak Time Rebate program, and the Summer Discount Plan “is one of SCE’s largest and most effective demand response programs.”⁹³ In reply briefs, the Joint Demand Response Parties rescind their proposal but continue to recommend a larger reliance on “bring your own devices” programs.⁹⁴

⁸⁹ SCE-03 at 11 and Table II-4.

⁹⁰ SCE-03 at Table III-7 and Table III-8.

⁹¹ Joint Demand Response Parties Opening Brief, July 24, 2017, at 22.

⁹² *Ibid.*

⁹³ SCE Reply Brief, August 4, 2017, at 10.

⁹⁴ Joint Demand Response Parties Reply Brief, August 4, 2017, at 14.

SCE's proposal to decrease the incentive level for the Summer Discount Plan is perplexing. In 2017, SCE paid approximately \$63 million⁹⁵ to program participants; but proposes to decrease those incentives to \$23.279 million in 2022.⁹⁶ While expressing concern about the effect the decreased incentives would have on attrition rates,⁹⁷ SCE also maintains these are more appropriately-valued incentive levels for the program.⁹⁸ SCE does not provide any evidence why these reduced incentive levels are more appropriately-valued. SCE asserts that residential customer attrition is due to increased event hours both in terms of the number of hours in a given year as well as previous years.⁹⁹ In comment to the proposed decision, the Joint Demand Response Parties highlight the concern about increased attrition due to increased event hours.¹⁰⁰ Joint Demand Response Parties question why SCE would request the increase in hours for the Peak Time Rebate, given the experience with attrition.¹⁰¹ SCE states that the proposed increase in hours to the Peak Time Rebate is to mirror the Summer Discount Plan dispatch window in preparation for the shift of Summer Discount Plan participants to the Peak Time Rebate program.¹⁰² SCE proposes to continue

⁹⁵ SCE-03 at 11, line 3.

⁹⁶ SCE-02 at 31, Table III-7.

⁹⁷ *Id.* at 30.

⁹⁸ SCE-03 at 11.

⁹⁹ SCE-02 at 26. SCE also notes that commercial program customer attrition has also increased with the number of dispatched hours, although not as severe. (*See* SCE-02 at 28.)

¹⁰⁰ Joint Demand Response Parties Opening Comments to the Proposed Decision, November 29, 2017 at 8.

¹⁰¹ JDP-01 at 30.

the Summer Discount Plan until such time as the Peak Time Rebate program can replace it in terms of capacity; the Peak Time Rebate program currently has 22,000 customers.¹⁰³

Included in SCE's plans for the Summer Discount Plan over the next five years are efforts to manage the number of events and the associated event hours, and efforts to improve customer communications. Given that SCE is moving toward replacing the Summer Discount Plan with Peak Time Rebate, SCE should have a transition plan in place. According to SCE, Peak Time Rebate is anticipated to experience an increase of approximately 10,000 customers each year beginning in 2019 through 2022.¹⁰⁴ Simultaneously, the Summer Discount Plan is anticipated to experience an average decrease of approximately 11,314 customers each year over the same amount of time.¹⁰⁵ The record indicates that SCE does not anticipate the replacement of Summer Discount Plan with the Peak Time Rebate program to occur within the 2018-2022 budget cycle or possibly the subsequent budget cycle. Hence, the acknowledgement by SCE that the proposed incentive levels could increase attrition is disconcerting. Equally perplexing is the SCE acknowledgement that the attrition is related to the increase in the number of event hours.¹⁰⁶

This Decision authorizes the proposed budget of \$37.680 million for the Summer Discount Plan and \$8 million for the Peak Time Rebate program for

¹⁰² SCE-02 at 32.

¹⁰³ SCE-03 at 34.

¹⁰⁴ *Ibid.*

¹⁰⁵ SCE-03 at 18, Table IV-5.

¹⁰⁶ SCE-02 at 26.

2018-2022. SCE shall provide a report on the attrition rates in its 2020 update and a comparison with anticipated rates. If the report indicates that the decrease in the incentives are negatively affecting the program, SCE shall halt all further decreases in incentives and develop a proposal to correct the problem. The report shall also explore the impact of the increase in hours. Additionally, SCE shall include a Summer Discount Plan transition plan that estimates the anticipated increase in Peak Time Rebate along with the anticipated decrease in the Summer Discount Plan for the next ten years, beginning in 2021.

At this time, we deny the request to increase the number of hours for the Peak Time Rebate. The record shows the transition to Peak Time Rebate will not occur over the next program cycle. Until we can determine the effect on the Summer Discount Plan of increasing the number of event hours, it is not reasonable to increase the number of hours in the Peak Time Rebate program. All other changes to SCE's Peak Time Rebate program are approved.

This Decision authorizes the incentives for the Summer Discount Plan as proposed by SCE but increases the incentive cap for years 2021 and 2022 as shown in Table 8 below, as a contingency plan. SCE is authorized an incentive cap of \$12.4 million for the Peak Time Rebate program.

Table 8 Summer Discount Plan Annual Incentive Cap (millions)					
Year	2018	2019	2020	2021	2022
Cap	\$51.630	\$42.667	\$35.625	\$29.177	\$23.279
Contingency	\$51.630	\$42.667	\$35.625	\$35.625	\$35.625

6.4.2. Capacity Bidding Program

There are four overarching issues with respect to the Capacity Bidding Program: 1) statewide uniformity; 2) program changes adopted in D.16-06-029;

3) revising the penalty structure; and 4) adoption of a residential Capacity Bidding Program. This Decision determines in Section 6.1.1 that the Utilities are not required to provide uniform parameters for the Capacity Bidding Program; that discussion is not repeated here. With respect to the program changes adopted in D.16-06-029, this Decision clarifies below that that all *proposed* (emphasis added) changes to the Capacity Bidding Program will be addressed in this proceeding. However, as discussed below, the Commission has previously determined that the current penalty structure for the Capacity Bidding Program is reasonable and because the Joint Demand Response Parties provide no new evidence that contradicts this determination, this Decision upholds the finding and maintains the current penalty structure for the Capacity Bidding Program. Lastly, as further described below, this Decision requires SCE and SDG&E to pilot a one-year residential Capacity Bidding Program. Proposals for the pilot shall be included in the 2020 mid-cycle advice letter filing. This schedule will allow time to complete a review of proposed new baselines, as discussed in section 10.3 of this Decision.

The Scoping Memo for the proceeding noted that program designs ordered by D.16-06-029, *e.g.*, changes to SCE's Capacity Bidding Program, will not be litigated in this proceeding. In its protests to this proceeding, the Joint Demand Response Parties questioned why SCE's Capacity Bidding Program proposal should be litigated separate from its Application. In reply, SCE explained that SCE is not proposing any further changes in its Capacity Bidding Program and that the tariff changes it filed in early 2017 reflect the modifications adopted in D.16-06-029. SCE seems to have interpreted the Scoping Memo such that any proposed changes to the Capacity Bidding Program are out of scope. This Decision clarifies that only the program designs ordered

by D.16-06-029 for program year 2017 are out of scope. However, the Advice Letter SCE stated would be filed in early 2017 was not filed until August 2017 and Energy Division dismissed the advice letter due to the delay.¹⁰⁷ Because the 2017 adopted changes were never implemented, all Capacity Bidding Program changes proposed by parties in this proceeding are in scope.

D.16-06-029 denied a request by the Joint Demand Response Parties to require the Utilities to adopt modifications to the payment bands and penalties for the Capacity Bidding Program; the Joint Demand Response Parties reiterate the request in this proceeding. The Joint Demand Response Parties had argued that the payment bands and penalties treat the 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.”¹⁰⁸ In D.16-06-029, the Commission stated that the proposal to adopt energy imbalance charges, in lieu of capacity de-rates, does not appropriately consider the risks imposed upon the Utilities.¹⁰⁹

In the instant proceeding, the Joint Demand Response Parties claim that the current penalty structure does not reflect the actual costs incurred by the Utilities for non-performance or under-performance of a demand response resource in the wholesale market.¹¹⁰ Furthermore, the Joint Demand Response Parties maintain that because supply-side resources are integrated into the

¹⁰⁷ Rejection of SCE Advice Letter 3642-E by Commission Energy Division Director, November 3, 2017.

¹⁰⁸ D.16-06-029 at 59.

¹⁰⁹ *Ibid.*

¹¹⁰ Joint Demand Response Parties Opening Brief, July 24, 2017, at 26.

CAISO market, it is appropriate that the penalty structure passed along to aggregators reflects the costs, and method of cost causation, incurred for underperformance of the resource.¹¹¹ In response, SDG&E states that the Joint Demand Response Parties do not appropriately describe the Capacity Bidding Program as a pay-for-performance program. SDG&E explains that penalties in the Capacity Bidding Program are meant to encourage response to an event and that failure to respond cannot be remedied later in the month, as is the case of the CAISO wholesale penalty structure.

The Capacity Bidding Program offers monthly capacity payments to customers for reducing loads to a pre-determined level and then provides additional energy payments or penalties based on the actual load reduction for a given event. The Capacity Bidding Program is a pay-for-performance program and the penalties have been structured to encourage performance. If the Commission adopted a penalty structure similar to the CAISO, which assesses performance on a monthly basis, the incentive to perform during each event would not be as robust. Additionally, if customers are concerned about the penalty level, customers have the option to adjust the pre-determined load level on a monthly basis. This Decision finds the penalty structure for the Capacity Bidding Program to be appropriate given the focus on performance and the ability of customers to revise the load reduction level on a monthly basis. If the ability to revise the load reduction level changes, parties should file a petition for modification of this Decision.

¹¹¹ *Id.*, at 26-27.

The last overarching issue addresses the question of whether to require SDG&E and SCE to adopt a residential Capacity Bidding Program. Pointing to the PG&E request to open all program options to residential aggregators,¹¹² the Joint Demand Response Parties recommend the Commission require SDG&E and SCE to offer an additional residential option for third-party providers, suggesting it could spur significant growth in residential demand response participation. Stating that it investigated and discussed a residential option with the aggregators, SDG&E claims that the aggregators were not interested or “lacked the means to set up or target residential customers.”¹¹³ As a result, SDG&E determined it would not focus on adding residential customers. While seeing value in such a program, SCE cautions that the current baseline is not appropriate for this resource type.¹¹⁴ In response to opening briefs, the Joint Demand Response Parties concede that, while the Commission should require a residential Capacity Bidding Program in the future for both SDG&E and SCE, appropriate baselines need to be developed first.

This Decision concludes that new alternative baselines are necessary for demand response programs and in particular, the residential option of the Capacity Bidding Program. Section 10.3 of this Decision contains a broader discussion of baselines.

With respect to a residential option of the Capacity Bidding Program, it is prudent to require SDG&E and SCE to explore a residential option on a pilot basis, following the adoption of appropriate baselines. If successful, a full

¹¹² PGE-01 at 2-8 and 2-11.

¹¹³ SDG&E Reply Brief, August 4, 2017, at 16.

¹¹⁴ SCE Reply Brief, August 4, 2017, at 8-9.

program could be implemented in the next program cycle. SCE recommends the Commission allow SCE to propose a residential option of the Capacity Bidding Program in the 2020 portfolio update.¹¹⁵ SDG&E's reasoning for not requesting a residential option is based on undocumented discussions. SDG&E also states that adding residential customers may have an adverse effect on the cost-effectiveness of Capacity Bidding Program, without providing any reasons or facts.¹¹⁶ Given SDG&E's current cost-effectiveness results, exploring other options should not be so easily dismissed.

As this Decision has authorized PG&E to allow residential aggregator participation in all options of its Capacity Bidding Program, it is reasonable to require both SCE and SDG&E to pilot such an option in their service territories following the adoption of updated baselines. Information gathered through the pilot in addition to the experience of PG&E's program could lead to the creation and requested approval of a residential Capacity Bidding Program in the 2023-2027 portfolio application. Accordingly, SCE and SDG&E include proposals and budgets for these pilots in their 2020 mid-cycle update. Based upon their respective current Capacity Bidding Program budgets, SCE is authorized a one-year budget of \$77,000, plus an incentive cap of \$928,000 and SDG&E is authorized a one-year budget of \$708,000 to administer the pilot and award incentives.¹¹⁷ Furthermore, this Decision directs SCE and SDG&E to

¹¹⁵ *Id.* at 8.

¹¹⁶ *Id.* at 16.

¹¹⁷ A pilot budget was determined by dividing the Capacity Bidding Program budget by five, and again by three (residential demand response customers are about one-third the number of commercial and industrial customers).

participate in the collaborative effort between PG&E and other stakeholders to create a streamlined residential enrollment process.

6.4.2.1. PG&E

PG&E's Capacity Bidding Program is available for commercial, industrial, or agricultural customers and can be enrolled through self-aggregation or through a third-party aggregator. The Settlement addresses several issues pertaining to Capacity Bidding Program including credit and collateral requirements, tariff changes, penalty structure, and enrollment process, which we have discussed and determined to be in public interest in Section 4.

The Settlement did not resolve the availability hours and implementing a residential option for this program.

Capacity Bidding Program hours: PG&E proposes to change its Capacity Bidding Program operating hours from 11:00 a.m. – 7:00 p.m. to 1:00 p.m. 9:00 p.m. to improve grid support and cost-effectiveness. Opposing PG&E's proposal, CLECA notes that CAISO will not move its resource adequacy availability assessment hours from 1:00 p.m.- 6:00 p.m. to 4:00 p.m. – 9:00 p.m. until 2019. PG&E does not deny CAISO's plans, but adds that its loss of load expectations heat map analysis is already showing greatest value from 6:00 p.m. to 9:00 p.m.

The Joint Demand Response Parties requests that the Commission require PG&E to return its Capacity Bidding Program hours to their current hours, arguing that PG&E has not substantiated why the program hours need to be modified.¹¹⁸ The Joint Demand Response Parties adds that PG&E is anticipating changes in resource adequacy Availability Assessment Hours that have not been

¹¹⁸ Joint Demand Response Parties Opening Brief, July 24, 20187, at 25.

adopted by the Commission in the resource adequacy proceeding and are not consistent with CAISO tariffs.¹¹⁹ The Joint Demand Response Parties do not consider the heat map analysis cited by PG&E equivalent to an analysis conducted by the Commission or CAISO.¹²⁰ The Joint Demand Response Parties point out to the importance of consistent rules across the Utilities and consistency of Capacity Bidding Program operating hours and resource adequacy availability assessment hours.¹²¹ The Joint Demand Response Parties adds that third-party providers rely on Commission and CAISO rules as written. According to the Joint Demand Response Parties, allowing Utilities to modify those rules before adoption lead to market uncertainty and customer confusion.¹²²

PG&E explains that PG&E's loss of load expectations analysis is already showing a need for the proposed hours. PG&E's analysis is clearly not equivalent to a Commission decision; however, we cannot simply ignore PG&E's conclusions. Therefore, we see value in PG&E's effort to be proactive and proposal to adjust the operating hours based on the grid needs. However, we also want to allow time for current program participants to adjust to these new hours and prevent customer disenrollment due to abrupt changes. Therefore, we direct PG&E to offer the new operation hours on an optional basis until the CAISO or the resource adequacy proceeding adopts new resource adequacy

¹¹⁹ Joint Demand Response Parties Reply Brief, August 4, 2017, at 17.

¹²⁰ Joint Demand Response Parties Reply Brief, August 4, 2017, at 17.

¹²¹ Joint Demand Response Parties Reply Brief, August 4, 2017, at 18.

¹²² Joint Demand Response Parties Opening Brief, July 24, 2017, at 17-18.

availability assessment hours or PG&E provides more evidence in the mid-cycle review of grid need.

PG&E also proposes to open the Capacity Bidding Program options to residential aggregators with three options for participation: The Prescribed Option, similar to the current program with changes to event duration and program hours, the Elect option that allows the aggregator or self-aggregator to specify their own bidding price, and the Elect+ Option (Elect Option with expanded hours).

We see value in increasing the number of options available to aggregators and self-aggregators which will allow them to have more control over hours of participation and price. With the modification on default operation hours, we approve PG&E's proposed changes. PG&E shall file a Tier One Advice Letter within 60 days of the issuance of this decision updating its Capacity Bidding Program tariff language to be consistent with this Decision.

Table 9 PG&E's Budget Request Capacity Bidding Program						
Program Year	2018	2019	2020	2021	2022	Total
(in thousands)	\$ 4,104	\$ 4,104	\$ 4,104	\$ 4,104	\$ 4,104	\$ 20,518

PG&E requested \$20.5 million for its Capacity Bidding Program for the 2018-2022, as shown in Table 9. The Commission authorized \$10.6 million for Capacity Bidding Program and Critical Peak Pricing Program for the 2017 bridge year. PG&E's average annual request is \$4.5 million less than what was authorized for 2017. PG&E explains that the reduction is due to a decrease in Capacity Bidding Program incentives resulting from updated load impacts that are lower than estimated from 2017. This offsets a slight increase in requested

funds for SmartAC due to labor and contract cost inflation.¹²³ PG&E's request is reasonable. PG&E is authorized a five-year budget of \$20.5 million.

6.4.2.2. SCE

In its testimony, SCE explains that in D.16-06-029 the Commission approved several changes to its Capacity Bidding Program and, therefore, SCE expected to file tariff changes in early 2017 to reflect the adopted modifications. SCE does not propose further changes to its Capacity Bidding Program and requests a five-year budget of \$1.083 million for the Capacity Bidding Program and an incentive cap of \$13.946 million. Several aspects of the Capacity Bidding Program have already been addressed in this Decision and are not reiterated here.

This Decision adopts the proposal by SCE to maintain the changes adopted in D.16-06-029 with the exception of the 20-minute notification requirement. As previously noted, SCE did not file the advice letter requesting to make the adopted changes to the programs until August 2017 and Energy Division staff dismissed the advice letter based upon the filing delay.¹²⁴ In requesting approval of the 20-minute notification in the 2017 demand response bridge funding, SCE relied upon a proposed CAISO requirement which was never adopted by the Commission. Because the Commission in the Resource Adequacy proceeding has not adopted the requirement of a 20-minute notification, this Decision determines that changing the Capacity Bidding Program notification time is unnecessary. If a 20-minute notification requirement is adopted by the Commission in the Resource Adequacy proceeding, SCE may submit a Tier 2

¹²³ PGE-01 at 6-10 and PGE-08 at 3.

¹²⁴ See Commission Energy Division Disposition Letter, November 3, 2017.

Advice Letter requesting the change in the Capacity Bidding Program. All other changes to SCE's Capacity Bidding Program that were adopted in D.16-06-029 remain in effect, including the authorized budget for those program changes. SCE is authorized a Capacity Bidding Program budget of \$1.083 million for the 2018-2022 program cycle with an incentive cap of \$13.946 million.

6.4.2.3. SDG&E

SDG&E's proposals to modify the Capacity Bidding Program are adopted with two exceptions: 1) the request to implement a 20-minute notification time in the Capacity Bidding Program is denied based upon a lack of justification, and 2) the concept of the Capacity Bidding Program trigger based on price is adopted but SDG&E shall file a proposal describing the method to determine the price triggers; final price triggers will be adopted in a future decision.

SDG&E requests to modify its Capacity Bidding Program in several ways: 1) reduce the number of products offered from nine products to four; 2) extend the hours events may be called to 9:00 p.m.; 3) offer the option to be called from two hours up to four hours; 4) offer the option of two hours of availability during either 11:00 a.m. to 7:00 p.m. or 1:00 p.m. to 9:00 p.m.; 5) simplify the trigger, basing it only on price rather than price and heat rate, and establish the trigger of \$75/MWh for day-ahead and \$140/MWh for day-of; and 6) update incentives, as indicated in Table 10 below, with a 20-minute notification for bidding into the CAISO real time market. SDG&E requests a budget of \$10.623 million in order to implement the Capacity Bidding Program.

Table 10 SDG&E Capacity Bidding Program Incentive Structure¹²⁵			
Product	\$/kW-Year	Monthly Max. Event Hours	Annual Max. Event Hours
Day-Ahead 11:00 A.M. – 7:00 P.M.	\$65	24	144
Day-Ahead 1:00 P.M. – 9:00 P.M.	\$78	24	144
Day-Of - 20 min 11:00 A.M. – 7:00 P.M.	\$74	24	144
Day-Of - 20 min 1:00 P.M. – 9:00 P.M.	\$88	24	144

The Joint Demand Response Parties support most of SDG&E's proposed changes with two exceptions: 1) the 20-minute response time for real time participation; and 2) the method by which price triggers were established and how they will be updated. No other party opposes the proposed changes.

The Joint Demand Response Parties contend that SDG&E is conflating the 20-minute response time request with CAISO's deferred proposal for a 20-minute dispatch requirement for demand response resources to qualify for local capacity. Because neither the Commission nor the CAISO has implemented this requirement, the Joint Demand Response Parties argue that the request is premature. However, SDG&E clarifies that the request is not based upon a CAISO proposal but rather to provide time for SDG&E to execute necessary tasks and for the customer to achieve the load shed to meet CAISO real time requirements. In testimony, SDG&E states that when the CAISO awards SDG&E's bids, SDG&E must notify Capacity Bidding Program enrolled customers as soon as possible so that they have time to reduce their load. SDG&E contends that a 20-minute notification time best enables SDG&E to bid

¹²⁵ SDG&E Opening Brief, July 24, 2017, at 32, Table 6.

into the real time market and notify the customers. But SDG&E does not provide an explanation of why it needs to decrease the notification time to customers by 10 minutes. SDG&E has not provided sufficient evidence that real-time participation requires a 20-minute notification time in the Capacity Bidding Program; the request to implement a 20-minute notification time in the Capacity Bidding Program is denied.

In comments to the proposed decision, SDG&E cautioned that if the Commission denies both Day-Of programs because of the 20 minute notification, SDG&E would not be able to bid into the Day-Of CAISO market, which is SDG&E's intent with this program as a supply side resource. SD&E request the Commission modify the Day-Of program to allow a two-hour notification time prior to the start of the Day-Of event.¹²⁶ This is a reasonable request that allows SDG&E to continue to participate in the Day-Of market. SDG&E's proposed Day-Of product with a two-hour notification time is approved.

SDG&E states that D.16-06-029 directed the Utilities to develop a statewide Capacity Bidding Program trigger based on price and a heat rate, and file an advice letter implementing the new trigger; SDG&E complied on August 1, 2016.¹²⁷ In its testimony, SDG&E asserts combining the heat rate and price trigger is unnecessary and confusing to customers and, thus, recommends basing the trigger solely on an up-to-date energy price. SDG&E proposes a price trigger of \$75/MWh for the day-ahead option and \$140/MWh for the day-of option, stating that this will be clearer to customers and simplify market

¹²⁶ SDG&E Opening Comments to the Proposed Decision, November 29, 2017 at 12.

¹²⁷ SGE-01 at 23.

bidding.¹²⁸ The Joint Demand Response Parties agree that the concept of a trigger based on price is reasonable, and, “on the surface, simpler for customers to understand.” However, Joint Demand Response Parties assert that “absent more detail on how the price triggers were set and what method will be used to update the triggers,” the Commission should not adopt them.¹²⁹ During the evidentiary hearing, when asked how the updated triggers were determined, SDG&E indicated the triggers were “determined with our electric and fuel group which bids program into CAISO.”¹³⁰

This Decision finds the concept of the Capacity Bidding Program trigger based on price to be reasonable and adopts it. However, without additional information on the method by which the triggers were determined or will be updated, the Commission cannot determine whether these specific proposed price triggers are reasonable. Within 30 days of the issuance of this Decision, SDG&E shall file a proposal in this proceeding describing the method used to determine and then update the proposed price triggers. Parties to this proceeding may file comments on the method no later than 14 days after the filing of the method by SDG&E. A future decision will make a determination on the reasonableness of the method. Again, to assist in improving the cost-effectiveness of SDG&E’s programs, the Capacity Bidding Program administrative budget is reduced by 10 percent. SDG&E is authorized a five-year budget of \$10.535 million for the Capacity Bidding Program.

¹²⁸ *Ibid.*

¹²⁹ Joint Demand Response Parties Opening Brief, July 24, 2017, at 31 citing the Evidentiary Hearing Transcript at 187.

¹³⁰ *Ibid.*

6.5. Emerging and Enabling Technologies

Emerging and Enabling Technologies provide customers incentives to install automated technologies that allow automated response to a demand response event or price signal without the customer taking an action. Programs under this category include the Automated (Auto) Demand Response programs. This category also enables research into new technology, equipment, processes and products. The Auto Demand Response program offers incentives to customers to help offset the cost of purchase and installation of behind-the-meter distributed energy technologies such as energy efficient devices, energy storage, electric vehicle charging stations and controls that interoperate using generally accepted industry open standards or protocols.¹³¹

There are two overarching issues with respect to this category of activities: 1) whether to include Auto Demand Response costs in the cost-effectiveness analysis of eligible programs, and 2) whether there is a competitive neutrality issue with respect to technology incentives. We address these two issues separately here and then discuss each utility's programs in detail below.

6.5.1. Overarching Issues

With respect to the cost-effectiveness analysis, PG&E and Joint Demand Response Parties propose excluding Auto Demand Response costs from the cost-effectiveness tests of programs that enroll customers enabled by the Auto Demand Response program.¹³² The basis for this proposal is that the Capacity Bidding Program is the only PG&E program that qualifies for Auto Demand

¹³¹ D.12-04-045 at 144.

¹³² PG&E Opening Brief, July 24, 2017, at 30; Joint Demand Response Parties Opening Brief, July 24, 2017, at 42.

Response program incentives and is subject to the cost-effectiveness analysis.

D.15-11-042 did not require the Utilities to include Auto Demand Response costs in cost-effectiveness analyses of other qualifying demand response programs because they are either pilots or rates.¹³³ ORA is concerned that exclusion of incentive costs will lead to an inaccurate depiction of program costs.

Pursuant to D.15-11-042, the Commission clarified that technical assistance activities, as well as pilots do not require a cost-effectiveness analysis using the adopted protocols.¹³⁴ However, technology incentive costs are required to be included in the cost-effectiveness analysis of qualifying demand response programs, such as the Capacity Bidding Program.¹³⁵ This creates disparities when comparing these programs with each other, *i.e.* the Demand Response Auction Mechanism versus the Capacity Bidding Program. On the other hand, excluding these costs from reporting and analyses of eligible programs may not provide an accurate evaluation of these programs and does not comport with the demand response principle of transparency.

Accordingly, the Utilities are directed to *report* the Auto Demand Response costs associated with all programs that qualify for Auto Demand Response incentives and the cost-effectiveness ratios with and without the Auto Demand Response incentives in subsequent applications. The Utilities shall clearly indicate 1) the total amount of Auto Demand Response incentives excluded from

¹³³ The other PG&E programs that qualify for Auto Demand Response incentives but are either pilots or rates include the Demand Response Auction Mechanism, Peak Day Pricing, Smart Rate, and the Excess Supply and Supply II pilots. (See PGE-01 at -22.)

¹³⁴ D.15-11-042, Figure 1 at 49.

¹³⁵ *Ibid.* All costs attributable to the program or activity requesting funding are to be included in the cost-effectiveness analysis.

portfolio cost-effectiveness analysis as required by D.15-11-042 and 2) the costs associated with customers participating in each program qualifying for Auto Demand Response incentives. This will ensure transparency while creating a more level playing field for customers participating in these programs. The Commission will consider the Capacity Bidding Program cost-effectiveness ratios both with and without the incentives, thus having full transparency of the amount of the incentives.

With respect to the issue of competitive neutrality, Joint Demand Response Parties contend that directly-enrolled and third-party enrolled customers do not have equal access to technology incentives and that access to technology funded by all ratepayers should be available to all ratepayers. Furthermore, the Joint Demand Response Parties argue that by not allowing all customers equal access to advanced equipment and the incentives for installing this equipment, the Utilities have an unfair advantage over third party providers. OhmConnect argues that this inconsistent treatment is contrary to the goal of demand response whereby demand response shall be market-driven leading to a competitive, technology-neutral, open market in California with a preference for services provided by third-parties.¹³⁶

Parties provide several examples of this alleged inequity. Both Joint Demand Response Parties and OhmConnect point specifically to SDG&E's Technology Incentives program in comparison to its Technology Deployment program. A customer wanting to participate in the Technology Deployment program must enroll in an SDG&E direct-enroll demand response program for

¹³⁶ OhmConnect Opening Brief, July 24, 2017, at 4.

one year before the customer is eligible to participate in a third-party provider program such as the Capacity Bidding Program or the Demand Response Auction Mechanism. OhmConnect also contends the \$75 thermostat credit offered to SCE's Peak Time Rebate customers is another example of this inequity and requests the Commission to require SCE to offer this credit to all demand response customers.

SCE calls these arguments unreasonable. SCE asserts that third-party demand response programs are not operating on equal terms with utility-administered demand response programs because they are not regulated and subject to cost-effectiveness evaluations. SCE maintains that because a utility cannot verify the cost-effectiveness of funds spent on technologies used in third-party programs, it would contravene Commission directives to provide such technology. Further, SCE submits that "the cost of these incentives should be incorporated into OhmConnect's competitively-based offers into the wholesale marketplace."¹³⁷ SCE contends that ratepayer funded incentives are available to customers in a third party program when it is providing resource adequacy capacity through the auction mechanism to SCE because OhmConnect includes the cost of incentives in its bid. SCE also explains that the \$75 incentive offered in the Peak Time Rebate program is not a technology incentive but rather an incentive to enroll in Peak Time Rebate.¹³⁸

Pursuant to D.15-11-042 Auto Demand Response, as a technical assistance program, is not analyzed for cost-effectiveness. Therefore, the argument presented by the Utilities is not valid. Providing technology incentives to both

¹³⁷ SCE Opening Brief, July 24, 2017, at 24.

¹³⁸ SCE Reply Brief, August 4, 2017, at 14.

third-party customers and utility customers enrolled in supply side programs/activities not subject to cost-effectiveness analysis provides improved customer choice, an adopted demand response principle. Accordingly, the Utilities shall offer Auto Demand Response technology incentives to customers of all supply side programs/activities not subject to cost-effectiveness analysis; this includes the Demand Response Auction Mechanism and, where applicable, pilots.

In comments to the proposed decision, SCE requests the Commission facilitate a workshop to discuss undefined policies including: eligibility frequency, eligible devices, etc. A workshop is a reasonable way to ensure understanding of the policy. To prepare for such a workshop, the Utilities are directed to develop a set of draft guidelines for this policy. No later than 60 days from the issuance of this decision, the Utilities shall file the draft guidelines in this proceeding. A workshop notice and further direction will be issued following the filing of the draft guidelines.

At this time, the Commission refrains from adopting this policy for demand response *non-event based* rate programs, such as time of use rates. In comments to the proposed decision, PG&E cautions against adoption of such a policy at this time “since it has not been proven that Auto Demand response enabled technologies are appropriate to help time of use customers manage daily load shifting to fixed time periods where no automated dispatch Auto Demand Response signal will be used.”¹³⁹ Furthermore, there is insufficient information in the record with respect to the cost of such a policy. Accordingly, the

¹³⁹ PG&E Opening Comments to Proposed Decision, November 29, 2017 at 9.

Commission will continue to explore the potential and implications of such a policy in order to develop pilots in the 2020 update.

6.5.2. PG&E

Under the emerging and enabling technologies category, PG&E requests \$20.4 million for Auto Demand Response and \$7.2 million for Demand Response Emerging Technologies, as shown in Table 11. PG&E states that the core of the Auto Demand Response program design will remain the same, but proposes several improvements to the Auto Demand Response program: (1) maintaining residential Auto Demand Response incentives requested in 2017 by AL 3744-G-B/4886-E-B during 2018-2022 cycle, (2) evaluating how to expand the approach of the joint energy efficiency/ Auto Demand Response device rebate proposed in 2017 to other behind-the-meter technology programs beyond energy efficiency programs; (3) piloting a new incentive structure based on the incremental cost of the Auto Demand Response communication technology embedded in the end-use device rather than on \$/kWh demand response potential of the end-use device in order to prevent overpayments; (4) investigating the feasibility of midstream and upstream incentives; (5) performing a load impact study in early 2020; and (6) excluding all Auto Demand Response costs from the cost-effectiveness calculation of the Capacity Bidding Program and overall demand response portfolio.¹⁴⁰

Joint Demand Response Parties support PG&E's activities in this area and especially the pilot program,¹⁴¹ as the pilot creates a new opportunity for participation that is agreeable to third-party technology providers.

¹⁴⁰ PG&E-01 at 2-23.

¹⁴¹ Joint Demand Response Parties Opening Brief, July 24, 2017, at 39.

PG&E proposes to continue to provide program updates to the Commission through the bi-annual report and Emerging Technology Coordinating Council quarterly meetings.

Table 11						
PG&E's Budget Request for Emerging and Enabling Technologies						
	2018	2019	2020	2021	2022	Total
AutoDR	\$ 4,006	\$ 4,050	\$ 4,090	\$ 4,130	\$ 4,171	\$ 20,446
DR Emerging Technology	\$ 1,380	\$ 1,416	\$ 1,446	\$ 1,478	\$ 1,510	\$ 7,230

The Commission authorized \$3.601 million for Auto Demand Response and \$1.375 million for Demand Response Emerging Technology for the 2017 bridge year. PG&E's average annual budget request is \$559,000 more than what was approved for 2017. PG&E attributes this increase to expanding the Auto Demand Response Program to the residential market.¹⁴²

PG&E's request is reasonable and should be approved.

6.5.3. SCE

Auto Demand Response Technology Incentive Program and Programmable Communicating Thermostat Incentive Program

SCE's Auto Demand Response program provides eligible SCE customers with incentives to install automated load control equipment or a system, such as an energy management system at a non-residential customer site. Customers are required to have an interval meter and participate in at least one qualifying demand response program. SCE proposes no changes to the program from parameters adopted for program year 2017. SCE requests to continue providing a \$75 rebate to residential customers for the purchase of an eligible

¹⁴² PGE-01 at 6-11 and PGE-08 at 3.

programmable communicating thermostat. SCE proposes to extend the rebate offer to non-residential customers. Moreover, SCE requests to move the incentives for this program into the budget for the Auto Demand Response program to streamline all of SCE's demand response technology incentives under one program.¹⁴³ SCE requests a five year budget of \$43.639 million. Aside from the discussion regarding equity and fairness, which has been addressed above in Section 6.5.1, no party protests the Auto Demand Response program.

SCE's proposal for the Auto Demand Response program is reasonable and should be adopted. Moving the incentives for the thermostat into the Auto Demand Response budget line improves transparency. SCE requests to continue providing a \$75 rebate to residential customers for the purchase of an eligible programmable communicating thermostat. However, SCE also contends that the \$75 rebate is an incentive to join the Peak Time Rebate program.¹⁴⁴ This Decision considers the \$75 incentive to be appropriately categorized as a technology incentive. Accordingly, this Decision authorizes a five-year program budget of \$43.639 million.

Emerging Markets and Technologies Program

The Emerging Markets and Technologies program provides co-funding and cost-sharing with third parties, private industry, and numerous stakeholder groups for pilots, demonstrations, and testing activities to advance demand response enabling technologies. SCE proposes to continue the existing activities for the 2018-2022 program cycle and focus on: 1) energy storage, integrated pilot programs, and expanding residential demand response; 2) a partnership with

¹⁴³ SCE-02 at 40.

¹⁴⁴ SCE Reply Brief, August 4, 2017, at 14.

Lawrence Berkeley National Laboratory for demand response assessments; and 3) EPRI core projects. SCE proposes a budget of five year budget of \$23.981 million.¹⁴⁵

The proposed annual budget for this program has more than doubled in comparison with 2017. SCE provides insufficient information regarding the proposed pilots, demonstrations and testing activities. Without additional information on these activities, it would not be in the ratepayer's best interest to authorize such a budget increase. This decision authorizes a five-year budget of \$14.61 million based on the 2017 authorized budget. SCE may offer additional information in the 2020 update for years 2021 and 2022. If the proposals are found reasonable, SCE may be granted total budgets for 2021 and 2022 of up to \$4.715 million each year, based on the amount requested for 2018 in this proposal.¹⁴⁶

6.5.4. SDG&E

SDG&E included its Technology Enabling programs under the heading of load modifying programs. For purposes of consistency across the Utilities, these programs are discussed under Emerging and Enabling Technologies. Furthermore, as noted by SDG&E, Technology Incentives and Technology Deployment programs are supporting programs that provide enabling technology.¹⁴⁷ Hence, these programs are categorized in this Decision as emerging and enabling technologies and not load modifying programs.

¹⁴⁵ SCE 10 and SCE 11.

¹⁴⁶ To be clear, the "total budget" includes the amount authorized in this Decision.

¹⁴⁷ SGE-05 at 2.

Technology Incentives Program (also known as Auto Demand Response)

SDG&E proposes to continue the program as approved in the 2017 bridge funding decision during the first three years (2018-2020) of this program cycle and propose any necessary modifications in the mid-cycle review (2020).

SDG&E requests a total budget of \$13.297 million for the five-year program cycle. Joint Demand Response Parties argue an equal access concern, which has been addressed above and will not be reiterated here. Furthermore, concerns regarding SDG&E's cost-effectiveness are discussed in Section 7.2.3 and will not be addressed here. However, because SDG&E's portfolio is not cost-effective, this Decision decreases the budget for this program by 10 percent to improve the cost-effectiveness results. This Decision adopts the program as proposed by SDG&E and authorizes a decreased budget of \$11.967 million.

Technology Deployment Program (formerly known as the Small Customer Technology Deployment Program)

SDG&E requests approval of the following program characteristics:

1) program is open to all customers regardless of size; 2) program has a "bring your own device" option; 3) program is open to technologies that can curtail load other than large energy management systems and upgrades covered by the Technology Incentives program; 4) incentives set at \$100 per kW per device (up to the cost of the device) where the load reduction can be determined by evaluation and measurement or engineering estimates; 5) technology can be signaled by the utility or vendor with appropriate vendor commitments; and 6) customers shall enroll in the Critical Peak Pricing rate, AC Saver, or (after one

year) the Capacity Bidding Program.¹⁴⁸ SDG&E requests a five-year budget of \$4.215 million for the Technology Deployment program.¹⁴⁹

The Joint Demand Response Parties oppose the requirement that customers wanting to participate in this program must enroll in a SDG&E-administered program for one year before enrolling in the Capacity Bidding Program or Demand Response Auction Mechanism and notes that this is not true of SDG&E's Technology Incentive program.¹⁵⁰ Citing past problems where third-party providers teamed up with vendors and enrolled customers in the Capacity Bidding Program but did not nominate the customers or nominated far less than the loads the shed test amounts indicated, SDG&E explains it was concerned of similar problems in the Technology Deployment program.¹⁵¹ Furthermore, SDG&E observes that the Technology Deployment does not have the same safeguards as the Technology Incentive program, where the customer only receives 60 percent of the incentive upfront and receives the remaining portion after performing for one year. However, SDG&E cautions that imposing the 60/40 requirement on the Technology Deployment program is administratively cost-prohibitive.

SDG&E underscores the differences between the Technology Deployment program and the Technology Incentive program, stating that the 60/40 requirement is cost-prohibitive. This is a reasonable assessment. However, requiring customers to enroll in a SDG&E-administered program for one year

¹⁴⁸ SGE-01 at 33.

¹⁴⁹ *Ibid* at 37.

¹⁵⁰ Joint Demand Response Parties Opening Brief, July 24, 2017, at 34.

¹⁵¹ SCE-01 at 35.

before enrolling in the Capacity Bidding Program or Demand Response Auction Mechanism is an unnecessarily strict safeguard for a thermostat. Moreover, the proposed safeguard results in a competitive barrier to third-party providers. As determined in Section 6.5.1, the Utilities shall offer Auto Demand Response technology incentives to customers of all programs not subject to cost-effectiveness analysis. Therefore, SDG&E shall implement a requirement that these customers must enroll in a demand response program, either a utility-administered program or a third-party program.

All other elements of SDG&E's proposal are reasonable and should be adopted. As was the case with the Technology Incentive program, we decrease the budget for the Technology Deployment program by 10 percent to address the low cost-effectiveness results. SDG&E is authorized a five-year program budget of \$3.794 million.

In comments to the proposed decision, SDG&E informs the Commission that while the new design of this program does not include providing programmable communicating thermostats, SDG&E still has thermostats in inventory and customers who previously applied to participate in this program. While SDG&E is attempting to install these thermostats prior to the end of 2017, it may not be possible. SDG&E requests authorization to complete installations in 2018 using the available 2017 funding.¹⁵² This request is reasonable and does not undermine customer certainty.¹⁵³ SDG&E's request to complete installations of thermostats in program year 2018 using 2017 authorized funds is granted.

Emerging Technology Demand Response Program

¹⁵² SDG&E Opening Comments to Proposed Decision, November 29, 2017 at 7.

¹⁵³ UCAN Reply Comments to Proposed Decision, December 4, 2017 at 5.

SDG&E proposes to continue its Emerging Technology program with the same structure as 2017 but recommends prioritizing fast demand response, Integrated Demand Side Management technologies, technologies that aid full market integration, permanent load shifting technologies, and technologies that enhance the ratepayer value to the Technology Incentive program.¹⁵⁴ SDG&E anticipates executing four to six projects per year based on 2015-2016 projects. SDG&E requests a budget of \$3.87 million for the five-year program cycle. No party opposed SDG&E's proposal or proposed budget.

SDG&E's Emerging Technology program proposal is adopted with one modification. SDG&E shall not pursue new permanent load shifting projects as the Commission has determined them not to be cost-effective. Here again, in order to address the low cost-effectiveness results for the portfolio, this Decision decreases SDG&E's Emerging Technology budget by 10 percent. SDG&E is authorized a five-year program cycle budget of \$3.483 million.

6.6. Demand Response Pilots

6.6.1. PG&E

PG&E proposes to continue with two pilot programs, Supply Side II demand response pilot (SSP II) and the Excess Supply demand response pilot, and evaluate their performance in the mid-cycle review.

According to PG&E, SSP II investigates the operational feasibility of utilizing demand response resources that are integrated in the wholesale energy markets and provide resource adequacy to address local distribution needs. This pilot was originally initiated in 2013. Most recently, the Commission approved SSP, the predecessor of SPP II, in D.16-06-029. PG&E explains that it proposes to

¹⁵⁴ SGE-01 at 50-51.

continue with this pilot because (1) past pilots have shown that it will take more than a year to get meaningful results on utilizing demand response resources for distribution services, and (2) this work will entail exploring ways to operationalize the integration of wholesale demand response resources with distribution operations.¹⁵⁵

PG&E's other pilot proposal, Excess Supply Demand Response Pilot, aims to explore how customers can mitigate situations of excess supply by shifting their load. This pilot was initiated in 2015 and the Commission extended the pilot through 2017 in D.16-06-029. PG&E reports that progress has been made on the pilot's objectives and additional results will be available by the end of 2017, but PG&E adds that not all the objectives will be met by the end of 2017.¹⁵⁶

PG&E requests a \$10.7 million for the Supply Side Pilot and \$3 million for the Excess Supply pilot program, as shown in Table 12. Approximately one third of this budget is reserved for incentives to be used in the pilots.¹⁵⁷

Table 12 PG&E's Budget Request for Pilots (in thousands)						
Program Year	2018	2019	2020	2021	2022	Total
Supply Side Pilot	\$ 2,083	\$ 2,114	\$ 2,141	\$ 2,170	\$ 2,199	\$ 10,706
Excess Supply	\$ 596	\$ 605	\$ 612	\$ 620	\$ 629	\$ 3,062

PG&E's requested budget is approximately \$77,000 more per year than what was authorized for 2017 to account for inflation.

¹⁵⁵ PG&E-01 at 2-27 and 2-28.

¹⁵⁶ PG&E-01 at 2-30.

¹⁵⁷ PG&E-01 at 6-8 and PGE-08 at 3.

ORA does not support funding these pilots through 2022 and argues that the Commission should authorize these pilots based on the results of the mid-cycle review.

We find that the Supply Side II pilot has a compelling problem statement in that it considers using integrated demand response that provides resource adequacy, for local distribution reliability needs, using storage, electric vehicles, and other demand response. PG&E appropriately proposes a mid-cycle assessment, offers several metrics to measure success, and promises to work on an evaluation, measurement and verification plan with the Demand Response Measurement and Evaluation Committee, and share it with Energy Division. Similarly, the Excess Supply Pilot (XSP) is designed to address important issues such as manually dispatching load consuming demand response and testing various related retail (compensation, interaction with retail rates), wholesale (triggers, baselines) and reliability issues (interaction with distribution system and congestion there). In addition, PG&E presents reasonable justification for extending the pilots. However, PG&E prematurely assumes success of the pilots and requests five-years of funding.

The Commission's guidance provided in D.12-04-045 clearly states that "pilots should be limited in scope and duration." Therefore, we authorize PG&E to extend the pilots only for the 2018-2020 period and decline to approve their funding for 2021 and 2022. PG&E is authorized a budget of \$8.15 million for the Supply Side and Excess Supply Pilots for 2018 through 2020. Should the Energy Division determine in the mid-cycle review that the objectives of the pilots are not met and they should still be pursued, then the Energy Division can authorize up to the original requested budget for years 2021 and 2022. PG&E can continue to use two-way balancing accounts for the incentive portions of the

pilot programs. Furthermore, PG&E shall develop its evaluation, measurement, and verification plan with metrics with input by the Demand Response Measurement and Evaluation Committee and file a Tier One Advice Letter no later than 90 days from the issuance of this Decision.

6.6.2. SCE

SCE's Charge Ready Pilot and its associated budget are adopted. The Charge Ready Pilot grew out of a settlement agreement between SCE and intervenors in A.14-10-014, SCE's application proposing the Charge Ready Program.¹⁵⁸ In the settlement, SCE agreed to create a demand response program to further clean air, climate change, and load management objectives.¹⁵⁹ SCE requests a two year budget of \$429,953. No party opposes this pilot.

The goal of SCE's Charge Ready Pilot is to 1) support the objectives of: a) achieving installation of grid-integrated infrastructure to support one million zero emission vehicles by 2020; b) accelerating the adoption of 1.5 million zero emission vehicles by 2025; and c) supporting clean air and climate change objectives; and 2) provide for management of electric vehicle load to support the grid in a manner that delivers benefits to SCE customers. Simultaneously, the Charge Ready Pilot will also support Senate Bill 350 and reduce pollution through activities such as off-peak charging. SCE's Charge Ready pilot will reward customers who reduce demand to an agreed level of energy reduction

¹⁵⁸ SCE-02 at 46 and Footnote 42. *See* A. 14-10-0013, "Motion for Approval of Phase I Settlement Agreement between and Among, SCE, American Honda Motor Co, Inc., CALSTART, The California Energy Storage Alliance, Chargepoint, Inc., Coalition of California Utility employees, Environmental Defense Fund, General Motors, LLC, Greenlining Institute, Natural Resources Defense Council, NRG Energy, Inc., Oresource adequacy, Plug In America, Sierra Club, The Utility Reform Network, and Vote Solar."

¹⁵⁹ *Ibid.*

upon notice from SCE; evaluate incentive models; and provide advance notice using OpenADR technology.

As this pilot furthers clean air, climate change, and load management objectives and complies with the settlement approved by the Commission, it is reasonable and should be adopted. This Decision authorizes a two-year budget of \$429,953.

6.6.3. SDG&E

Armed Forces Pilot

SDG&E proposes to continue its Armed Forces Pilot through 2019 and then convert the pilot into the program beginning in 2020. This pilot began in 2017 in response to the Commission eliminating the Demand Bidding Program, in which the U.S. Navy was the sole customer for several years. Based on the Capacity Bidding Program, this pilot is designed as a gateway pilot to test the ability of the Navy and other branches of the Armed Forces to participate in day-of Auto Demand Response.

SDG&E explains that, in 2016, the Navy completed its direct digital controls program where it has installed building controls systems with demand response capabilities at key San Diego area bases. There are 30 Navy facilities or building with working Auto Demand Response and an additional identified potential 154 building sites. The pilot will allow the Navy a mechanism to participate in demand response events on a more consistent basis.

SDG&E requests a two-year budget of \$1.638 million for the pilot. Given this is a five-year program cycle, SDG&E also requests to move the pilot to program status beginning in 2020, contingent upon Commission evaluation and approval, and requests a three-year program budget of \$3.159 million. SDG&E explains that the annual increase in budgets is to account for anticipated growth as

additional Auto Demand Response buildings are brought into the pilot/program. Both UCAN and ORA find fault with SDG&E's proposed Armed Forces pilot and budget.

UCAN supports a demand response program for the Armed Forces but argues that the cost-effectiveness tests indicate total resource cost results of 0.5 for the pilot. Noting that the program the pilot is based on, the Capacity Bidding Program day-of program, has a cost-effectiveness total resource cost result of 0.6, UCAN contemplates that the pilot would not achieve a higher result once becoming a program in 2020.¹⁶⁰ In response, SDG&E points out pilots are not required to comply with the cost-effectiveness protocols and demonstrate a cost-effective result of 1.0. Furthermore, SDG&E maintains that because the pilot began implementation this year, the cost-effectiveness results in the record do not reflect data from actual pilot operation.

ORA contends that because SDG&E failed to include a sufficient evaluation, measurement, and verification plan (Evaluation Plan) as required by D.12-04-045, the Commission should deny funding authorization.¹⁶¹ ORA explains that without more specificity on how each pilot objective will be met, the proposal does not comply with Commission requirements for pilots. Because of the proposed brief time to move from pilot to program, ORA recommends that the Commission require SDG&E to articulate how it will evaluate the Armed Forces Pilot before authorizing a budget. ORA suggests that the Commission require SDG&E to supplement its proposal with a detailed Evaluation Plan with standards and metrics to measure the pilot's customer enrollment success,

¹⁶⁰ UCAN Opening Brief, July 24, 2017, at 19-20.

¹⁶¹ ORA Opening Brief, July 24, 2017, at 9-11.

cost-effectiveness, and achievements. Noting this may delay a decision in the proceeding, ORA contends that the supplement is necessary to ensure just and reasonable rates pursuant to Public Utilities Code Section 451.¹⁶²

In response, SDG&E asserts that ORA overlooks SDG&E testimony that outlines the evaluation, measurement and validation approach to the pilot and includes a load impact evaluation, a baseline analysis and a process/market evaluation. SDG&E states that it will use the results of these efforts in combination with program participation results to make a recommendation on whether to convert the pilot to a program or terminate it.

SDG&E proposes to transition the Armed Forces pilot into a program in 2020 prior to an evaluation by the Commission. While this pilot may be experimental, the Commission must be able to determine if transitioning from pilot to program is in the ratepayers' best interest. This Decision, therefore, adopts a three-year Armed Forces pilot and authorizes SDG&E a three-year pilot budget of \$2.587 million. SDG&E is authorized to continue the pilot in 2020 at the funding level requested for 2019 while the Commission determines whether the pilot should transition to a full program beginning in 2021. Furthermore, SDG&E shall work with ORA to develop a more detailed Evaluation Plan as described further below.

ORA's suggestion to improve SDG&E's Armed Forces Evaluation Plan to include metrics is reasonable. The metrics shall be developed to quantify the objectives in Table 13 below and success must be measureable. In addition to the objectives in Table 13, SDG&E shall include the objective to test the proposed

¹⁶² *Ibid.*

incentive level and penalty structure, *i.e.*, details on the proposed incentive levels and penalty structure to ensure these are set appropriately. SDG&E shall file a Tier One Advice Letter no later than 90 days from the issuance of this Decision with the agreed upon Evaluation Plan.

The Commission expects a thorough and complete evaluation of the first three years of the pilot¹⁶³ including recommendations on whether the Commission should adopt it as a program beginning in 2021; this Decision does not authorize funding for the program at this time. The Armed Forces pilot evaluation and recommendations along with requested further rate recovery shall be submitted with the mid-cycle update in 2020. If the evaluation indicates success of the pilot based upon the results of agreed-upon metrics, SDG&E may be authorized an additional two-year budget, up to \$2.211 million, the amount previously requested in SDG&E's application for 2021-2022.

<p style="text-align: center;">Table 13 Objectives of the SDG&E Armed Forces Pilot¹⁶⁴</p>
<ul style="list-style-type: none"> • To test the ability of the customer to provide a quantity of Day-Of Auto Demand Response; • To test the feasibility of customer installed Auto Demand Response technologies; and • To test the feasibility of third-party control over customer systems.

Over-Generation Pilot

SDG&E's proposed Over-Generation Pilot is a two-year continuation of the pilot approved by the Commission in D.16-06-029. The objective of the pilot is to determine whether distributed energy storage facilities can effectively and

¹⁶³ The evaluation shall include results of pilot years 2017 through 2019.

¹⁶⁴ SGE-01 Appendix One at 30.

economically address two major concerns with renewable over-generation:

- 1) excessive export of distributed solar to the grid during non-peak periods; and
- 2) lack of flexible generation during demand response events. SDG&E plans to install a distributed storage unit at ten commercial customer facilities to effectively capture excess generation from on-site solar. During the traditional demand response season, SDG&E plans to use the distributed storage at the customers' facilities to address the system peaks. During non-demand response months, SDG&E plans to charge each customer's storage unit to help mitigate the impact of over-generation, and discharge the battery later in the day to potentially reduce the customer's daily peak loads. SDG&E requests a two-year budget of \$1.422 million for the pilot and, if approved by the Commission, a three-year budget of \$2.209 million to move the pilot into a program beginning in 2020.

ORA opposes adoption of this pilot based on a lack of an adequate Evaluation Plan to identify the standards or metrics used to determine if the pilot is successful. ORA highlights that the Evaluation Plan proposed by SDG&E focuses on accurately calculating the financial benefits to the customer rather than to SDG&E and ratepayers. Furthermore, ORA notes that while SDG&E states that equipment will provide the verification needed to display the efficacy of the pilot, SDG&E does not explain how the equipment data alone will provide sufficient information to determine whether the pilot can cost-effectively address over-generation. ORA recommends the Commission require SDG&E supplement its pilot proposal to include a detailed Evaluation Plan with standards and metrics to enable the Commission to determine the efficacy of this pilot.

In response, SDG&E agrees that an Evaluation Plan is important but maintains that “there are tried and true methodologies for evaluating pilots” and SDG&E will not deviate from them. SDG&E argues that expectations for a more detailed Evaluation Plan for an emerging pilot is unprecedented and presents a “chicken and egg” conundrum since one cannot provide more detail for an experimental program yet to be implemented.

As was the case with the Armed Forces pilot, SDG&E requests to transition the Over-Generation pilot into a program prior to the Commission evaluating the pilot. Therefore, this Decision adopts a three-year Over-Generation pilot and authorizes SDG&E a three-year budget of \$2.507 million. SDG&E is authorized to continue the Over Generation pilot in 2020 at the funding level requested for 2019, while the Commission determines whether the Over-Generation pilot should transition to a full program. Here again, SDG&E is required to work with ORA to develop a more detailed Evaluation Plan.

Similar to the Armed Forces pilot, SDG&E and ORA shall develop metrics to quantify the pilot’s objectives, as described in Table 14 below and success must be measureable. SDG&E shall file a Tier One Advice Letter no later than 90 days from the issuance of this Decision with the agreed upon Evaluation Plan.

The Commission expects a thorough and complete evaluation of the first three years of the pilot and recommendations on whether the Commission should adopt it as a program beginning in 2021; this Decision does not authorize funding for the program at this time. The Evaluation Plan and recommendations, along with requested further rate recovery, shall be submitted with the mid-cycle update in 2020. If the Evaluation Plan indicates success of the pilot based upon the results of agreed-upon metrics, SDG&E may be authorized

an additional two-year budget of up to \$2.148 million, the amount originally requested in the application.

Table 14 Objectives of the SDG&E Over-Generation Pilot¹⁶⁵
<ul style="list-style-type: none">• Whether distributed storage systems can effectively and economically address the concerns associated with renewable over-generation;• Feasibility of limiting excessive export of distributed solar to the grid during non-peak periods; and• Quantify and extrapolate the potential customer and system benefits of the stored renewable energy.

6.7. Evaluation, Measurement, and Validation

Evaluation, measurement, and validation activities assess demand response program attributes, allowing the Commission to evaluate program effectiveness. One major activity under this category is the Load Impact Protocols.

6.7.1. PG&E

During the 2018 – 2022 period PG&E proposes to support demand response with measurement and evaluation studies in the following three areas:¹⁶⁶

- Impact and process evaluations of existing PG&E demand response programs, including Base Interruptible Program, Permanent Load Shifting, Capacity Bidding Program, SmartAC, SmartRate and SmartMeter Enabled Program Evaluation, Peak Day Pricing, and Time-of-Use Rates: Activities in this area will provide information about program attributes, load reduction capacity and customer

¹⁶⁵ SGE-01 Appendix One at 34.

¹⁶⁶ PGE-01 at 5-15-2 and 5-8.

acceptance and form the basis for recommendations for resource adequacy, the long term procurement plan, integrated resource plan and demand response cost-effectiveness analyses. PG&E will continue to provide ex post and ex ante impact estimates.

- Demand Response Pilots: PG&E will evaluate the two proposed pilot programs to help structure future programs.
- Evolving Grid Needs: In order to respond to needs of the evolving grid, PG&E plans to conduct studies for impact evaluations for PG&E's proposed Auto Demand Response program and behind-the-meter technologies as well as continuing studies on customer behavior and load response.

PG&E's requests \$12.9 million for 2018-2022 (allocated proportionally across each year) to cover costs of measurement and evaluation, as shown in Table 15.¹⁶⁷

Table 15						
PG&E's Budget Request for Evaluation, Measurement, and Verification						
Program Year	2018	2019	2020	2021	2022	Total
(in thousands)	\$ 3,233	\$ 3,262	\$ 2,133	\$ 2,136	\$ 2,138	\$ 12,902

PG&E's request is \$675,000 less than what was authorized for 2017. PG&E attributes the decrease to not requesting funds for demand response research.

No party opposed PG&E's budget request. PG&E's request provides sufficient detail into its EM&V plan, and is in line with previous cycles' request for funding. However, as discussed previously, this Decision eliminates the Permanent Load Shifting program. The budget should therefore be reduced to

¹⁶⁷ PGE-01 at 6-11 and PGE-08 at 3.

\$11.78 million. This Decision finds PG&E's request for the measurement and evaluation budget reasonable as modified and approves it.

6.7.2. SCE

In its proposed evaluation, measurement and verification program, SCE proposes to conduct demand response load impact evaluations consistent with the guidelines in the Load Impact Protocols and conduct program process evaluations and general market surveys. SCE explains that process evaluations assess the way a program is designed, operated, and delivered but the process evaluations also document program operations for stakeholder visibility. Noting that the general consensus is that most programs do not need an annual process evaluation, SCE contends a periodic evaluation should provide sufficient time for processes to develop and demonstrate efficiencies.¹⁶⁸ SCE asserts that the decision to evaluate should be based on a needs assessment for all eligible programs. Furthermore, SCE proposes that the evaluation planning process should recognize that evaluation is a decision-making tool and scheduling should be determined in concert with the stakeholders. SCE requests a total five year budget of \$6.817 million, which includes \$1.714 million for project management of the evaluation studies and \$5.103 million to conduct load impact and process evaluation studies. No party objects to the proposal in this category or the requested budget.

This Decision agrees with SCE that evaluation scheduling should be determined in concert with the stakeholders. No later than April 30, 2018, SCE is directed to hold a stakeholder meeting to discuss the evaluation planning process and develop a five-year schedule. No later than June 1, 2018, SCE shall

¹⁶⁸ SCE-02 at 61.

submit a five-year plan for its Evaluation, Measurement and Verification activities via a Tier One Advice Letter. SCE's Evaluation, Measurement, and Verification proposal is reasonable and should be adopted. SCE is authorized a five-year budget of \$6.09 million because as discussed previously, this Decision eliminates the Permanent Load Shifting program.

6.7.3. SDG&E

SDG&E's Evaluation, Measurement and Validation proposal has three categories of activities: 1) load impact evaluation; 2) customer research; and 3) research and analytical support. SDG&E explains that D.08-04-050 adopted load impact protocols that establish the load impact evaluation requirements for demand response programs including ex post load impacts, ex ante results and 10-year forecast load impacts. In terms of customer research, SDG&E proposes to use process evaluations and other survey-based research during the 2018-2022 program cycle but most likely will occur in time for the mid-cycle review. SDG&E contends that it is prudent to budget additional funds for ad hoc research needs as they arise, such as additional weather and baseline analysis. However, SDG&E provides no specific projects for either the customer research or the research and analytical support categories. SDG&E requests a five-year budget of \$6.439 million.

No party opposes the requested budget for this category. However, given the need to improve cost-effectiveness of the portfolio and the lack of any specific projects identified by SDG&E for research and analytical support, this Decision decreases the evaluation, measurement and validation budget by 10 percent. SDG&E is authorized a five-year budget of \$5.795 million.

6.8. Marketing, Education, and Outreach

This category includes statewide marketing and demand response core marketing activities, but does not include integrated demand side management marketing activities, which are contained in the Utilities' energy efficiency program budgets.

6.8.1. Overarching Issue of Competitive Neutrality

Contending that the Utilities have a significant competitive advantage over third-party providers in terms of access to customer-specific data, OhmConnect proposes that the Commission require the Utilities to create an online demand response program portal for demand response programs provided by both Utilities and third-party providers. OhmConnect explains that the intent of the portal is to level the playing field between the Utilities and third-party providers and promote customer awareness and choice of demand response programs.¹⁶⁹

In response, SCE states that it does not object to the recommendation for an online demand response portal that includes the name and logo of the third party provider, the programs provided and a brief description, and a link to the provider's website. However, SCE maintains that "further discussion is necessary to determine the extent of SCE's responsibility for managing the portal" and that the issue is more appropriately addressed in the AB 793 proceeding or the Statewide Marketing, Education and Outreach proceeding.¹⁷⁰

As described below, this Decision directs each of the Utilities to update their websites to ensure the Utilities' main demand response web page includes

¹⁶⁹ OhmConnect Opening Brief, July 24, 2017, at 10.

¹⁷⁰ SCE Reply Brief, August 4, 2017, at 15.

the list of demand response third-party providers operating in their territory, and their associated logos, the name(s) of the third-party provider's program(s), and a two-sentence description of the program(s) (submitted to the Utility by third-party providers no later than 30 days from the issuance of this decision), and a link to the third-party providers' website (also provided by the third-party no later than 30 days from the issuance of this decision.) The Utilities shall ensure the update is viewable by customers no later than March 1, 2018. To ensure complete customer choice, this page shall also include a brief description of the utility's demand response programs in similar formatting.

This Decision agrees that in order to provide a level playing field between the Utilities and third-party providers and ensure customer choice, the Utilities should include a link to a list of the third-party providers on each utility's demand response homepage. While not objecting to the inclusion of this information on its web site, SCE suggests that discussion and management of this information should be addressed in either the AB 793 proceeding or the Statewide Marketing, Education, and Outreach proceeding. These two suggestions are discussed separately.

First, SCE suggests the Commission address the issue of a third-party provider portal in the Statewide Marketing Education and Outreach proceeding, A.12-08-007. This recommendation is infeasible as the Statewide Marketing Education and Outreach Roadmap filed by the statewide implementer on April 5, 2017 via Tier 1 Advice Letters specifically states that because demand response and air conditioner cycling are a lower priority and specific to each energy provider, there will be minimal statewide customer engagement messaging on demand response and air conditioner cycling. Messaging will be limited to encouraging customers to contact their energy provider to learn how

to help manage the energy used by their appliances.¹⁷¹ Accordingly, this Decision declines to adopt the proposal by SCE to address the issue of an online portal in A.12-08-007.

SCE also suggests the Commission address this issue through work being done to comply with Assembly Bill (AB) 793.¹⁷² The Commission implemented AB 793 through the adoption of Resolution E-4820, which addressed several Utility advice letters filed in August 2016. With respect to marketing, the Utilities requested approval of a joint marketing plan in the Advice Letters, which contained detailed assumptions about the direction in which the marketplace for energy management technologies is headed in the state and current market barriers for energy management technologies that the joint plan seeks to overcome. In addition, the plan put forward a statewide approach to marketing energy management technologies that includes specific approaches, goals, objectives and how best to target the residential, low income and small and medium customer market segments.

Resolution E-4820 found that the Utilities should provide greater support to their online marketplaces where consumers can become aware of energy management technologies offerings available to them, including updates of the marketplace to contain all measures relevant to AB 793. Additionally, the

¹⁷¹ Advice Letter DDB-1, April 5, 2017, Appendix A: Five-Year Marketing, Education and Outreach Strategic Roadmap at 32.

¹⁷² AB 793 (Stats. 2015) directed the Utilities to develop a program in their demand side management portfolios to provide incentives to residential and small and medium business customers to acquire energy management technologies by January 1, 2017. AB 793 also required the Utilities to develop a plan by September 30, 2016, to educate residential and small and medium customers about incented energy management technologies offerings available to them.

resolution required SCE and SoCalGas to create an energy technology marketplace that includes EE, demand response, and AB 793 related technologies. Resolution E-4820 required these websites to be updated or created by the fourth Quarter of 2017. However, the websites required by Resolution E-4820 are focused on technology devices, not programmatic information. Hence, the Commission should not rely upon these websites as substitutes for information on third-party provider programs. It is reasonable, however, that the websites required by E-4820 be used as templates to provide the information requested by OhmConnect. The Utilities shall ensure that the information on these third-party providers are copied and transferred to the main demand response offering page no later than March 30, 2018, subject to review by the Commission's Energy Division. To be clear, this main demand response offering page shall include all demand response offerings available in the utility's service territory. This will enable the utility's customers to have a clear understanding of all demand response choices available to them, thus complying with the demand response principle of customer choice. In comments to the proposed decision, parties express three concerns, which we address below.

First, SDG&E suggests that requiring the Utilities to provide information on third-party providers limits the Utilities' right to free speech. SDG&E states, however, that it is willing to post such information if it is permitted to prominently disclaim any responsibility for the content of such posts.¹⁷³ PG&E supports adding the disclaimer and requests that each of the Utilities be allowed

¹⁷³ SDG&E Opening Comments to Proposed Decision, November 29, 2017 at 12.

to develop its own disclaimer, but PG&E is open to developing standardized language with SCE and SG&E.¹⁷⁴ Joint Demand Response Parties argue that any disclaimer should be limited to making clear that the information has been provided by the listed entities and is not the responsibility of the individual utility.¹⁷⁵ This Decision allows each of the Utilities to post a disclaimer stating that the information has been provided by the third-party provider and the utility is not responsible for the content of the information; the Utilities shall each work with the Energy Division to develop a final disclaimer with standardized language.

Second, SCE requests that the third-party providers listed on the main demand response webpage be confined to those providers registered with the Commission.¹⁷⁶ Joint Demand Response Parties argue against such limitations stating that third-party aggregators do not need to register with the Commission.¹⁷⁷ OhmConnect offers a solution whereby a qualified third-party provider: 1) has a valid demand response service agreement with the utility; 2) has executed a demand response provider agreement with the CAISO; and 3) is registered with the Commission as a third-party demand response provider in good standing.¹⁷⁸ PG&E maintains that the third-party provider should be participating in the utility's portfolio. We adopt a modified version of these

¹⁷⁴ PG&E Reply Comments to Proposed Decision, December 4, 2017 at 4.

¹⁷⁵ Joint Demand Response Parties Reply Comments to Proposed Decision, 4, 2017 at 5.

¹⁷⁶ SCE Opening Comments to the Proposed Decision, November 29, 2017 at 14

¹⁷⁷ Joint Demand Response Parties Reply Comments to the Proposed Decision, December 4, 2017 at 5.

¹⁷⁸ OhmConnect Reply Comments to the Proposed Decision, December 4, 2017 at 5.

parameters: a qualified third-party demand response provider shall have executed a demand response contract with the utility; the contract can either be for providing demand response aggregator services or to provide demand response through the demand response auction mechanism.

Third, the Joint Demand Response Parties recommend that the proposed decision be modified to require the Utilities to drive customers to each of the Utilities' home page and use marketing funds to increase customer awareness of their demand response service options.¹⁷⁹ SDG&E and PG&E argue against this request. PG&E states that it is not the Utilities' role to actively promote or direct customers to demand response web pages and contends that these web pages should be a source of neutral information, not a marketing tool to promote individual demand response providers and aggregators.¹⁸⁰ The Utilities' demand response main web page should be an educational/informational tool as well as a marketing tool. This Decision confirms that it is the role of the Utilities to ensure that customers are provided with a clear and complete set of demand response options available to them. This helps to ensure customer choice, a principle of demand response. However, it is not the responsibility of the Utilities to ensure that customers click through to the websites of third-party providers, only that customers have the ability to click through. With that said, within 60 days of the issuance of this Decision, the Utilities shall each file a Tier One Advice Letter describing how they will inform their customers about the existence of the main demand response web page that includes a list of all

¹⁷⁹ Joint Demand Response Parties Opening Comments, November 29, 2017 at 12.

¹⁸⁰ PG&E Reply Comments to Proposed Decision, December 4, 2017 at 4. (See also SDG&E Reply Comments to Proposed Decision, December 4, 2017 at 2-3.)

demand response program options in the utility's service territory, including the utility and third-party offerings.

Resolution E-4820, adopted on April 7, 2017, required the Utilities to integrate demand response-related AB 793 offerings into the 2018-2022 demand response portfolio where feasible; the Utilities did not amend their filing. Accordingly, this Decision finds no reason to increase the budget to cover costs to replicate and add this information to the demand response offering web pages.

6.8.2. PG&E

As shown in Table 16, PG&E requests \$14.3 million for marketing, education, and outreach activities during the 2018-2022 program cycle to implement the following strategies:¹⁸¹

- Sustain multi-channel, multi-touch campaign year round;
- Coordinate demand response marketing;
- Bundle offers to deliver multiple benefits to customers through a single promotion; and
- Leverage partnerships.

PG&E plans to monitor and measure the success of the marketing strategies and adjust its marketing efforts accordingly.¹⁸² PG&E states that its overarching marketing objective is to “communicate available choices in demand response and their benefits in a simple way to customers’ needs.”¹⁸³ PG&E classifies its marketing goals by demand response programs: While PG&E is

¹⁸¹ PGE-01 at 2-31 and 2-32.

¹⁸² PGE-01 at 2-33.

¹⁸³ PGE-01 at 2-30.

prohibited from marketing its Base Interruptible Program by D.12-04-045, PG&E lists the following goals for its programs:

- Capacity Bidding Program – education
- Permanent Load Shifting Program – education, acquisition
- Auto Demand Response – education, acquisition
- SmartAC- education, acquisition, and retention.

PG&E’s marketing strategies include conducting outreach through multi-channel, multi-touch campaigns, coordinating demand response outreach with other Energy Savings Assistance Program, and bundling offers through a single promotion.¹⁸⁴

Table 16						
PG&E’s Budget Request for Marketing, Education and Outreach (in thousands)						
Program Year	2018	2019	2020	2021	2022	Total
Core Marketing and Outreach	\$ 2,484	\$ 2,547	\$ 2,603	\$ 2,660	\$ 2,719	\$ 13,013
Education and Training	\$ 252	\$ 262	\$ 270	\$ 279	\$ 288	\$ 1,350

PG&E’s funding request is \$336,000 less than what was authorized for 2017.¹⁸⁵ PG&E attributes this reduction to (1) expected acquisition costs related to SmartAC program and (2) reduction in marketing efforts for Permanent Load Shifting.

¹⁸⁴ PGE-01 at 2-32.

¹⁸⁵ PGE-01 at 6-12 and PGE-08 at 3.

We find PG&E's request reasonable, excluding the amount apportioned for Permanent Load Shifting program, which we eliminate for all three utilities. PG&E's Marketing, Education and Outreach budget is reduced by \$158,000 to reflect elimination of the Permanent Load Shifting Program and this Decision approves a budget of \$14.2 million.

6.8.3. SCE

SCE asserts that it has integrated and streamlined much of its marketing efforts into its Statewide Integrated Demand Side Management activities, pursuant to D.12-04-045 but contends that there is still a need to update program materials and communicate program changes to customers and aggregators. Thus, SCE proposes Marketing, Education, and Outreach efforts that are program-specific and "aim to promote awareness, notify changes, and increase enrollment...or aid program retention." SCE requests a five-year marketing, education, and outreach budget of \$14.336 million. Aside from the issue of competitive neutrality, no party objected to the proposals and budget requested by SCE.

SCE's Marketing, Education, and Outreach proposal and budget are reasonable and should be adopted, with the modification of the elimination of the Permanent Load Shifting Program. The requested average annual budget of \$2.867 million is a decrease of nearly three percent in comparison with the 2017 annual budget of \$2.966 million. SCE is authorized a five-year budget of \$14.336 million for its Marketing, Education, and Outreach proposal.

6.8.4. SDG&E

SDG&E states that all marketing, education, and outreach for its demand response programs is focused on SDG&E customers and entities that might do business in the SDG&E territory. SDG&E plans to use its funding to promote

three objectives: 1) increase awareness and understanding of the benefits of demand response; 2) increase awareness and participation in energy management technologies that can help customers realize energy savings; and 3) educate customers about the link between demand response and time-of-use rates. SDG&E proposes to use a variety of approaches to achieve these objectives depending upon the demand response program. SDG&E requests a five-year budget of \$4.502 million for marketing, education, and outreach focused on the programs identified in Table 17.

Table 17 SDG&E's Budget Request for Marketing Outreach and Education						
Program	2018	2019	2020	2021	2022	Total
Technology Incentives	\$63,411	\$77,368	\$79,143	\$80,960	\$82,819	\$383,701
Capacity Bidding Program	\$14,091	\$15,474	\$15,829	\$16,191	\$16,564	\$78,149
AC Saver	\$116,254	\$118,373	\$121,088	\$123,869	\$126,715	\$606,299
Technology Deployment	\$123,299	\$125,547	\$128,427	\$131,376	\$134,394	\$643,043
Base Interruptible Program	\$7,046	\$7,033	\$7,054	\$7,074	\$7,095	\$35,302
Time-of-Use	\$317,055	\$322,835	\$330,241	\$337,822	\$345,584	\$1,653,537
Critical Peak Pricing	\$211,370	\$215,223	\$220,160	\$225,214	\$230,390	\$1,102,357
Total						\$4,502,388

No party protested SDG&E's proposal for Marketing, Education, and Outreach or the requested five-year budget. SDG&E's Marketing, Education, and Outreach proposals are reasonable and should be adopted. In terms of the proposed budget, this Decision has decreased many of SDG&E's budgets in an attempt to improve the cost-effectiveness of the portfolio and the individual

programs, which are lower than acceptable. SDG&E requests a budget that remains relatively flat over the five year program cycle: \$.853 million in 2018 to \$.944 million in 2022. The 2022 budget request of \$.944 represents less than a 7 percent increase over the 2017 budget request of \$.885 million. At this time, this Decision declines to decrease the marketing budget because appropriate marketing and education should increase participation rates and cost-effectiveness. Accordingly, this Decision authorizes SDG&E a five-year marketing, outreach, and education budget of \$4.502 million.

6.9. Demand Response System Support

The Utilities use this category of funding to support improvements in the information technology systems, software and infrastructure and other system maintenance.

6.9.1. PG&E

As shown in Table 18, PG&E requests \$54.8 million to support the following activities: 1) Retail and Customer-Facing Activities (including the systems support for customer enrollment, aggregator enrollment, event forecasting, and event dispatch), 2) market activities (systems and personnel support for registration, bidding, dispatch), 3) Electric Rule 24 Operations and Maintenance (support for customer registrations and meter reprogramming for residential meters), and 4) demand response integration policy and planning.¹⁸⁶

Because the PG&E's Capacity Bidding Program proposal expands the program to residential customers, PG&E anticipates that it will need additional

¹⁸⁶ PG&E Opening Brief, July 24, 2017, at 44.

support to process enrollment, hardware performance upgrades to manage increased volume of data, among others.¹⁸⁷

Table 18 PG&E's Budget Request for Demand Response Systems Support						
(in thousands)	2018	2019	2020	2021	2022	Total
Support for Retail and Customer Facing Activities	\$ 4,235	\$ 3,794	\$ 3,879	\$ 3,966	\$ 4,055	\$ 19,928
Support for Market Activities	\$ 3,791	\$ 2,331	\$ 2,398	\$ 2,467	\$ 2,538	\$ 13,524
Rule 24 O&M	\$ 2,439	\$ 2,511	\$ 2,584	\$ 2,659	\$ 2,737	\$ 12,931
DR Integration Policy and Planning	\$ 1,576	\$ 1,629	\$ 1,677	\$ 1,727	\$ 1,778	\$ 8,386
Total	\$ 12,040	\$ 10,264	\$ 10,537	\$ 10,819	\$ 11,108	\$ 54,769

Overall, PG&E's request is 7.27 million lower than what was authorized for 2017.¹⁸⁸ PG&E attributes the difference to the completion of systems work related to integration with the CAISO markets.

PG&E is authorized a five-year budget of \$54.577 million.

6.9.2. SCE

SCE requests a five-year budget of \$29.210 million for Demand Response Systems Support. SCE proposes several new projects. To streamline market integration, SCE proposes to: a) reprogram CAISO-integrated residential meters from 60-minute to 15-minute intervals and non-residential meters from

¹⁸⁷ PGE-01 at 4-2.

¹⁸⁸ PGE-01 at 6-13 and PGE-08 at 3.

15-minute to 5-minute intervals (with a cap of 500,000 system accounts) at a cost of \$6.4 million; and b) reprogram demand response participating meters and fully integrate automation amount all systems utilized for demand response event dispatch at a cost of \$7.56 million. Describing its multiple vendor partnerships needed to support the demand response portfolio, SCE requests \$9.49 million for hosting and licensing fees. Noting that it has multiple technology initiatives that will continue to optimize demand response, SCE proposes to enhance its systems portfolio to support technology projects, enhancements, cyber security, and other smaller scale technology at a cost of \$3.23 million.

ORA contests SCE's request to reprogram the residential meters from 60-minute to 15-minute intervals as unnecessary. ORA explains that currently SCE has a waiver from the CAISO that allows SCE to use the 60-minute intervals and divide by four. ORA contends that SCE could request to extend that waiver or SCE could seek future waivers to meet CAISO's interval data requirements for residential customers participating in the Real Time market.¹⁸⁹ Furthermore, ORA asserts that SCE can operate its residential demand response programs without having to reprogram its meters. ORA also notes that the CAISO will consider metering requirements in Phase 3 of its Energy Storage and Distributed Energy Resources Initiatives. ORA surmises that SCE has many opportunities to continue operating its residential demand response resources without changes while participating in the wholesale market. Thus, ORA recommends the Commission reduce the budget by half.

¹⁸⁹ ORA Opening Brief, July 24, 2017, at 12.

Responding to ORA's request to decrease by the half the number of residential meters to be reprogrammed, SCE cautions that ORA's objection is premised on the presumption that CAISO will continue to waive the interval data requirements for residential customers participating in the Real Time market. SCE confirmed that it can continue to seek that waiver, but "runs the risk of not being able to integrate 260 megawatts" if the waiver is not extended.¹⁹⁰

This Decision grants the SCE proposal for Demand Response Systems Support including the project to reprogram residential meters from 60-minute intervals to 15-minute intervals at a cap of 500,000 service accounts. ORA's contention that the reprogramming is unnecessary at this time is based on the possibility that the CAISO may extend the waiver requiring 15-minute interval meters. While both ORA and SCE agree that the waiver could be extended and SCE could seek future waivers, they also both concede that without the waivers SCE is at risk of not being able to integrate 260 megawatts associated with the residential Summer Discount Plan program.¹⁹¹ This could also necessitate the procurement of additional resource adequacy resources. SCE asserts that the cost of procuring additional resource adequacy resources on an annual basis is greater than the one-time cost to reprogram the meters, surmising the procurement costs could be as much as \$9.3 million annually.¹⁹² This Decision finds that reprogramming the meters now at a cost of \$6.4 million is in the ratepayers' financial interest. Furthermore, if SCE waits to reprogram the

¹⁹⁰ SCE Reply Brief, August 4, 2017, at 19.

¹⁹¹ TR at 22-23.

¹⁹² SCE Reply Brief, August 4, 2017, at 19.

meters, not only could SCE spend additional and unnecessary procurement costs, the costs to reprogram the meters will most likely rise due to inflation.

SCE is authorized a five-year budget of \$29.21 million to: 1) reprogram CAISO-integrated residential meters from 60-minute to 15-minute intervals and non-residential meters from 15-minute to 5-minute intervals (with a cap of 500,000 system accounts) at a cost of \$6.4 million; b) fully integrate automation among all systems utilized for demand response event dispatch at a cost of \$1.163 million; c) cover hosting and licensing fees that support the demand response portfolio at a cost of \$9.49 million; d) enhance its systems portfolio to support technology projects, enhancements, cyber security, and other smaller scale technology at a cost of \$3.23 million and e) labor costs to administer the demand response systems at a cost of \$8.92 million.¹⁹³

6.9.3. SDG&E

SDG&E requests a five-year budget of \$8.830 million to effectively and centrally integrate, manage, and operate SDG&E's demand response programs. SDG&E explains the budget takes into consideration fundamental and high-level assumptions including the sequence of anticipated program implementation and the use of analogous/parametric estimating. SDG&E proposes that it will potentially pursue a strategic direction for the Base Interruptible Program and Technology Incentives with the goal of having the entire portfolio managed in the same core platform. Lastly, SDG&E includes funds for on-going software licensing to support program management and customer facing tools.

¹⁹³ SCE-02 at 67, lines 20-21; SCE-02 at 68, lines 12-15; SCE-02 at 69, lines 12-14, and SCE-02 at 70, lines 25-27 and SCE-02 at Table IX-17.

SDG&E maintains that its 2018-2022 budget is reasonable, and underscores that its proposed average annual budget for demand response systems support is \$1.766 million compared to \$2.306 million in 2017.¹⁹⁴ The description for this budget request does not provide sufficient information on each of the listed activities. For example, SDG&E states that it will potentially pursue a strategic direction for certain programs,¹⁹⁵ but does not explain the determining factors for whether it pursues the activity or not. Given that SDG&E's portfolio and its programs have been determined to be not cost-effective and given the limited justification for the activities, this Decision finds it reasonable to decrease the budget for demand response systems support by 10 percent. SDG&E is authorized a demand response systems support budget of \$7,947,649 for the five-year budget cycle.

6.11. Special Projects (Permanent Load Shifting)

The statewide Permanent Load Shifting program offers a one-time incentive (\$875/kW) to eligible customers for shifting cooling load from costly on-peak periods to less costly off-peak periods by using mature Thermal Energy Storage technologies to shift the load. All three Utilities request funding to continue the program and all three Utilities presented cost-effectiveness results of less than 1.0, as shown in Table 19 below.

¹⁹⁴ SGE-02 at 1.

¹⁹⁵ *Id.* at 2.

Table 19			
Permanent Load Shifting Budget Requests and Cost-Effectiveness TRC results			
	PG&E	SDG&E¹⁹⁶	SCE¹⁹⁷
Budget Request (\$million)	\$12.642 ¹⁹⁸	\$8.096	\$7.282 ¹⁹⁹
TRC Results	0.70 ²⁰⁰	0.20	0.10

Most parties call for eliminating or revising the Permanent Load Shifting program from the demand response portfolios due to low total resource cost results and low participation rates. Noting that it did not receive any new applications in 2016, SCE states that its program has had low participation since launching in 2013 and expects participation to remain consistent.²⁰¹ According to SCE, only six projects have been launched since 2013 and five are either in process of being installed or an inspection scheduled; an additional 12 projects were either withdrawn or declined.²⁰² SDG&E highlights that the high cost of the technology and implementation cost has produced only a handful of projects in the SDG&E territory since the program's inception.²⁰³ In the PG&E territory, out of seven applications submitted, three have been withdrawn, three are in

¹⁹⁶ SDG&E Opening Brief, July 24, 2017, at 31.

¹⁹⁷ SCE Opening Brief, July 24, 2017, at 31.

¹⁹⁸ This includes \$158,000 allocated to the marketing, education and outreach category and \$1.13 million for the evaluation, measurement and verification category for this program. (See PGE-01 at 6-9, line 39 and PGE-08 at 3.)

¹⁹⁹ This includes \$60,000 allocated to the marketing, education and outreach category for this program. (See SCE-02 at 38, Table V-10.)

²⁰⁰ PGE-01 at 7-2, Table 7-1, line 4.

²⁰¹ SCE-02 at 37.

²⁰² *Ibid.*

²⁰³ SGE-01 at 27.

progress and only one has been completed.²⁰⁴ All three Utilities suggest eliminating the program and incorporating it elsewhere, cutting the budget, or re-designing the program.²⁰⁵ Pointing to the same statistics, ORA and UCAN agree that the program should be eliminated due to its cost-effectiveness results and low participation.²⁰⁶

This Decision finds the Permanent Load Shifting program to be consistently not cost-effective and therefore, not in compliance with the Commission's demand response goal. Furthermore, over the past four years, few projects have been started and even fewer completed. The Permanent Load Shifting program proposals for all three utilities are denied. The Utilities shall complete the projects in process utilizing the 2017 funding. In comments to the proposed decision, SDG&E apprised the Commission that it has a large customer who began to implement a Permanent Load Shifting construction project but due to project delays is unable to begin providing demand response services until the middle of 2018. SDG&E request the Commission approve the use of 2017 authorized incentives to be paid in 2018 for projects already in progress. Since the customer has already made substantial investments to complete the project, SDG&E contends cancellation of the incentive would be onerous for the customer. UCAN supports SDG&E's request stating that the demand response program should provide certainty regarding incentives to customers who chose to participate. SDG&E's request is granted; SDG&E may use 2017 authorized

²⁰⁴ PGE-01 at 2-13.

²⁰⁵ See PGE-01 at 2-14, SGE-01 at 27, and SCE Opening Brief, July 24, 2017, at 31.

²⁰⁶ UCAN Opening Brief, July 24, 2017, at 21 and ORA Opening Brief, July 24, 2017, at 7-8.

Permanent Load Shifting incentives in 2018 for projects already in progress. No further funding will be authorized in the demand response portfolio.

7. Evaluating Program Cost Effectiveness

7.1. Cost-Effectiveness Threshold

D. 10-12-024 adopted a method for estimating the cost-effectiveness of demand response activities and required the Utilities to use the protocols for all future cost-effectiveness analysis of demand response programs. The protocols require the Utilities to use the four cost-effectiveness tests defined in the Standard Practice Manual: Total Resource Cost (TRC), Program Administrator Cost (PAC), Ratepayer Impact measure (PIM), and the Participant Test. These tests provide the net present value of the costs and benefits, discounted over the lifetime of the relevant demand response resource. These protocols also define costs attributable to a demand response program and use the Avoided Cost calculator developed by Energy and Environmental Economics, Inc. (E3) to calculate all avoided costs.

In D.12-04-045 the Commission took a flexible approach while using the protocols. It took into account not just the outputs generated by the protocols, but also the changes demand response programs were going through. The Commission also recognized that not all demand response programs might be cost-effective in all tests. In the same decision, when making a determination on the budget of a specific program, the Commission looked at the cost-effectiveness of a programs as well as the current transition of the demand response market.²⁰⁷ In order to allow for flexibility and recognize that transition, D.12-04-045 deemed programs with a TRC result of 1.0 to be cost-effective, but allowed for an error

²⁰⁷ D.12-04-045 at 30.

band of 10 percent, allowing programs with a TRC of at least 0.9 to be deemed cost-effective for the purposes of that proceeding.²⁰⁸

In this proceeding, even though the parties are not necessarily opposing revisiting the issue of threshold for cost-effectiveness, their positions vary as to where this issue should be addressed. SCE recommends that the Commission consider the threshold for cost effectiveness in the current demand response rulemaking.²⁰⁹ In contrast, ORA supports the Commission establish a threshold for cost-effectiveness for demand response programs in this proceeding, as it did in D.12-04-045. Asserting that a threshold of 1.0 TRC would align demand response with other distributed energy resources such as energy efficiency, ORA supports the requirement that utility demand response programs achieve a 1.0 TRC ratio.²¹⁰ ORA adds that enforcing a cost-effectiveness threshold of 1.0 for demand response programs would be consistent with the general cost-effectiveness requirement that benefits be greater than costs.

In D.10-12-024 the Commission determined that “[t]he relative weight given to any Standard Practice manual test in determining program approval or modification should be determined within the demand response budget proceedings.”²¹¹ Thus, this proceeding is the appropriate venue where we can modify the cost-effectiveness threshold so as to ensure that ratepayers’ money is allocated to the programs that yield positive returns.

²⁰⁸ D.12-04-045 at Finding of Fact No. 12.

²⁰⁹ SCE Opening Brief, July 24, 2017, at 34.

²¹⁰ ORA Opening Brief, July 24, 2017, at 14.

²¹¹ D.10-12-024 at Conclusion of Law No. 8.

D.12-04-045 found a cost-effectiveness threshold of 0.9 and above reasonable, recognizing that there might be a certain error band in the program analysis due to the first time use of the protocols to measure program cost-effectiveness.²¹² In this program review cycle, we determine that the Utilities have had sufficient experience with the Demand Response Protocols and have gone through the transition of integrating with the CAISO market. Therefore, the 10 percent error band is no longer needed. Going forward, our cost-effectiveness threshold will be a TRC cost-effectiveness ratio of 1.0 for each program or a continuous progress report on a program with qualitative and quantitative indicators. We can ensure that all regulated demand response programs are cost-effective and quantifiable benefits match or exceed the costs, only if we apply a TRC cost-effectiveness ratio of 1.0.

Having stated that, we will continue to be cognizant of the current state of the demand response industry including new programs objectives that may be established for the Utilities, *e.g.* targeting demand response for disadvantaged communities. Therefore, we may allow for continuous progress reporting on programs with quantitative and qualitative indicators in lieu of a 1.0 TRC ratio. However these progress reports should be viewed as exceptions rather than the norm.

7.2. Utility Reported Cost-Effectiveness Results

Tables 20 through 22 show the TRC, PAC and RIM results for each utility's demand response programs, as provided by the Utilities.²¹³

²¹² D.12-04-045 at 44.

²¹³ PGE-01 at 7-2; SCE-03 at 26; SDG&E Opening Brief, July 24, 2017, at 83.

Table 20 PG&E Cost-Effectiveness Results			
Program	TRC	PAC	RIM
Base Interruptible Program	1.6	1.3	1.3
Capacity Bidding Program	0.9	0.8	0.8
SmartAC	1.3	1.2	1.2
Permanent Load Shifting	0.7	1.6	0.5
Portfolio	1.2	1.1	1.0

Table 21 SCE Cost-Effectiveness Results			
Program	TRC	PAC	RIM
Agricultural Pumping Interruptible	1.09	0.86	0.86
Base Interruptible Program 15 Minute	1.78	1.34	1.34
Base Interruptible Program 30 Minute	1.68	1.27	1.27
Optional Binding Mandatory Curtailment	0	0	0
Rotating Outages	0	0	0
Scheduled Load Reduction Program	0	0	0
Summer Discount Program Residential	1.13	0.64	0.64
Summer Discount Program Commercial	0.99	0.49	0.48
Capacity Bidding Program day-ahead	1.15	1	0.99
Capacity Bidding Program day-of	1.20	1.05	1.02
Statewide Marketing, Evaluation, & Observation	0	0	0
Save Power Days	1.01	0.93	0.92
PLS	0.10	0.18	0.18
Portfolio	1.30	0.95	0.95

Table 22
SDG&E Cost-Effectiveness Results²¹⁴

Program	TRC	PAC	RIM
Base Interruptible Program	0.8	0.6	0.6
Capacity Bidding Program day-ahead	0.7	0.6	0.6
Capacity Bidding Program day-of	0.6	0.6	0.5
ACS DA	0.7	0.7	0.7
ACS DO	0.7	0.5	0.5
AFP	0.5	0.5	0.4
PLS	0.2	0.3	0.1
Portfolio	0.5	0.5	0.5

As we will discuss in more detail below, the cost-effectiveness ratios reported by the Utilities indicate that the majority of the demand response programs proposed by the Utilities for the 2018-2022 period are cost-effective.

7.2.1. PG&E

In its testimony, PG&E asserts that its 2018-2022 demand response portfolio is cost-effective with a TRC ratio of 1.2, including the Auto Demand Response Program costs, and 1.3 excluding the Auto Demand Response Program costs. PG&E provided cost-effectiveness results for its Base Interruptible Program, Capacity Bidding Program, SmartAC Program, and the Permanent Load Shifting Program by using the four Standard Practice Manual tests.

Only ORA raised concerns regarding the cost-effectiveness of PG&E's Capacity Bidding Program which has a TRC ratio of 0.9, including the Auto Demand Response costs. ORA recommends PG&E improve the cost-effectiveness of the program by removing nonperforming customers. In response, PG&E explains that because Capacity Bidding Program allows

²¹⁴ Based on the April 3, 2017 load impact report. SDG&E Opening Brief, July 24, 2017, at 83.

aggregators and aggregators make the dispatch decisions in their portfolio, PG&E does not have the right to remove customers from the aggregators' portfolio due to underperformance.²¹⁵ Referring to ORA's solution as unworkable, PG&E attributes the less than 1.0 TRC ratio of the CBP program to the following three factors:²¹⁶

- Because the Aggregator Managed Portfolio program was terminated, PG&E's Capacity Bidding Program had to bear more system costs.
- Customers participated in Aggregator Managed Portfolio program in the past are now enrolled in the Demand Response Auction Mechanism and the Base Interruptible Program more so than in the Capacity Bidding Program, lowering load impact estimates for the program.
- Auto Demand Response-enabled demand response participants do not provide sufficient load reduction to fully cover additional costs allocated to the Capacity Bidding Program.

In Section 6.5.1, we directed the Utilities to report in future applications incentive costs related to the Auto Demand Response program for all programs eligible for Auto Demand Response technical incentives. Excluding the incentive costs from the cost-effectiveness analysis increases the TRC ratio of PG&E's Capacity Bidding Program to 1.0, making it cost-effective. Nevertheless, we will continue monitoring how the Capacity Bidding Program's TRC ratio will change over time and may direct PG&E to implement changes in the mid-cycle review, if needed. With that, we find PG&E's demand response programs and demand response portfolio to be cost-effective.

²¹⁵ PG&E Opening Brief, July 24, 2017, at 28.

²¹⁶ PG&E Opening Brief, July 24, 2017, at 29.

7.2.2. SCE

In its testimony, SCE asserts that it conducted its demand response cost-effectiveness analysis as ordered by D.16-09-056, in compliance with the 2016 Demand Response Protocols adopted in D.15-11-042, and that its 2018-2022 demand response portfolio is cost-effective with a TRC score of 1.3.²¹⁷

Two parties raise concerns with SCE's program cost-effectiveness: First, ORA recommends that the Commission eliminate the Permanent Load Shifting program given its low cost-effectiveness ratio.²¹⁸

As we have discussed in Section 6.11, all programs report low cost-effectiveness ratios for the Permanent Load Shifting program. Consequently, we directed the Utilities to eliminate their Permanent Load Shifting programs. Therefore, the cost-effectiveness of the Permanent Load Shifting Program is moot for all three Utilities.

Second, the Joint Demand Response Parties do not agree with SCE's use of a G-factor of 100 percent in its cost-effectiveness calculations and recommend using a G-Factor of 105 percent for SCE's Capacity Bidding Program.²¹⁹ G-factor is one of the adjustment factors for demand response programs under the cost-effectiveness Protocols. G-factor accounts for demand response resources which can be called locally in geographical regions that are resource constrained. In its rebuttal testimony, SCE contends that Capacity Bidding Program does not qualify for the higher G-Factor.²²⁰ SCE agrees that Capacity Bidding Program is

²¹⁷ SCE-03 at 25.

²¹⁸ ORA-01 at 3-7.

²¹⁹ Joint Demand Response Parties Opening Brief at 41.

²²⁰ SCE-05 at 24-25.

integrated into the CAISO market and can be technically dispatched locally, but adds that sub-LAP²²¹ level is a higher dispatchability level than the level required to be considered locally dispatchable. SCE points out that the protocols do not specify at what specific dispatch level the G-factor adder applies. SCE explains that it uses the A-bank level, because “programs called at the Sub-LAP level are not guaranteed to realize local megawatts impacts at a targeted A-bank, B-bank, or circuit.”²²²

We find SCE’s approach of using a G-factor of 100 percent reasonable. Given that the protocols do not identify at what specific dispatch level the G-factor adder applies, SCE’s approach appears to be reasonable since it aims to capture guaranteed local megawatt impacts, hence prevent overestimating local load impacts.

With that, we find that SCE’s demand response programs and demand response portfolio are cost-effective.

7.2.3. SDG&E

SDG&E properly applied the Protocols and performed its cost-effectiveness analysis on a program by-program basis and on a portfolio basis which includes Marketing, Education & Outreach; Evaluation, Measurement & Validation; and Technical Incentives costs. SDG&E reports a

²²¹ SubLAPs (sub-Load Aggregation Points) defined by the CAISO are geographic areas that divide the electric grid. PG&E’s service territory is divided into 16 Sub-LAPs; SCE’s service territory is divided into 6 Sub-LAPs; and SDG&E’s service territory consists of one Sub-LAP. Sub-LAPs are the common unit at which day ahead load forecasting is done, and affect how loads can be aggregated into market bids. (See Phase 2 Appendices A – J 2025 California Demand Response Potential Study at 22 available at <http://www.cpuc.ca.gov/General.aspx?id=10622>.)

²²² SCE-05 at 24-25.

cost-effectiveness TRC ratio of 0.5 for its portfolio, using the April 2017 load impact update.

Despite the unsatisfactory cost-effectiveness results, SDG&E asserts that it is sound policy to approve SDG&E's application for the following reasons:²²³

- D.16-09-056 requirements reflect that demand response is still in transition. SDG&E asserts that automation provides opportunities for increasing customer participation in demand response programs while increasing technology costs. SDG&E plans to take advantage of these opportunities; however SDG&E contends that current cost effectiveness ratios do not reflect the potential value of technological advances. To give an example, SDG&E states that it did not include any value for circuit-level infrastructure deferral, *i.e.*, D Factor, in its cost-effectiveness analysis as the process is still under development in the Distributed Resources Planning proceeding.
- Cost-effectiveness results are lagging and do not reflect changes approved to take place in 2017 or those proposed to begin in 2018-2022.
- SDG&E's service territory has proportionally fewer large customers, smaller in area and load, therefore is more susceptible to addition or departure of large customers from a demand response program.
- The current analysis will provide more information in 2019.

SDG&E refers to parties' recommendations to improve the cost-effectiveness of SDG&E's portfolio as ineffective or speculative. SDG&E also adds that this is not the right time to drop programs from its portfolio because (1) demand response is second in the loading order and is a tool to reach

²²³ SDG&E Opening Brief, July 24, 2017, at 85-90.

state's climate goals; (2) it is not clear whether third parties can provide more cost-effective programs; and (3) the Commission's other proceedings such as integrated distributed energy resource and integrated resource planning proceedings are in the process of redesigning how distributed energy resources are valued.²²⁴

UCAN does not find SDG&E's arguments and reasons to maintain SDG&E's portfolio compelling. UCAN argues that greater automations should reduce costs and increase program effectiveness.²²⁵ UCAN asserts that even if all information technology costs were set to zero, SDG&E's portfolio would not be cost-effective. Furthermore, UCAN argues that locational demand response is currently not part of the portfolio; therefore any circuit level infrastructure deferral from this demand response portfolio will be incidental and should not be credited in evaluating cost effectiveness.²²⁶

To improve SDG&E's cost-effectiveness ratios, both ORA and UCAN recommend specific changes to SDG&E's programs. For example, ORA recommends removing underperforming customers from SDG&E's Capacity Bidding Program and AC Saver Day Of Program in order to decrease incentive amounts and improve cost effectiveness. In response, SDG&E explains that because Capacity Bidding Program is a pay-for-performance program, and incentives are paid only for actual load drops, removing underperformers would not help in improving cost-effectiveness.²²⁷ For the Savings Day Of program,

²²⁴ SGE-07 at EBM-2.

²²⁵ UCN-01 at 9.

²²⁶ UCN-01 at 12.

²²⁷ SGE-11 at BG-1.

SDG&E reports that it has already disenrolled a significant number of low performers from this program. SDG&E also considered removing the lowest 20 percent low-performing commercial customers and assessed the effect of reducing incentives to residential customers by an additional 17 percent in addition to the 10 percent it has proposed. However, SDG&E reports that the results of these additional changes led to TRC increases by 0.03, only.²²⁸

In response to UCAN's suggestion that SDG&E should reduce incentives for residential AC Saver Day Of Program customers to a one-time incentive paid to new enrollees without any annual incentive payments, SDG&E explains that there are no new customers anticipated for this program and they are concerned about customer attrition if they were to eliminate the annual incentives.²²⁹

SDG&E also cautions against eliminating programs in order to improve cost-effectiveness of the portfolio as the proportion of benefits and costs that the program contributes to the portfolio, as well as size of the program and the level of administrative fixed costs are factors that impact the cost-effectiveness of the program.²³⁰

Unlike PG&E and SCE, SDG&E's programs and portfolio are not cost-effective and that leads us to take additional steps to ensure that the budget we authorize in this decision is spent in a prudent manner. While we have taken steps throughout this Decision to reduce costs of certain programs administered by SDG&E and we approve SDG&E to continue to implement these programs, we also expect SDG&E to demonstrate progress and improve the

²²⁸ SGE-11 at BG-2.

²²⁹ *Ibid.*

²³⁰ SGE-11 at BG-3.

cost-effectiveness of its programs and portfolio. Towards this end, we direct SDG&E to (1) reduce its administrative budget by ten percent across all programs; (2) meet with Energy Division on a quarterly basis to discuss its progress in improving the cost-effectiveness of its programs and portfolio, and (3) file Tier 1 level advice letters in June 2019 and 2020 demonstrating the cost of its programs administered the previous year as well as the cost-effectiveness of these programs. Tier 1 advice letters shall also include the following information:

- Progress reports on all of the 2017 improvements SDG&E is in the process of implementing or has implemented, including a description of the improvement, its implementation status, and how it will impact or has impacted the TRC ratio;
- Report on the new changes and improvements to SDG&E's portfolio to improve the cost-effectiveness, including description of the programmatic change, timeline for implementation, and how it will impact the TRC ratio of the affected program; and
- Updated cost-effectiveness ratios based on changing conditions, *e.g.* programmatic changes, reductions in spending, market conditions, etc.

If SDG&E fails to demonstrate improvements in its program and portfolio cost-effectiveness through these advice letters, the Commission will direct SDG&E to file an application in 2019 or 2020 to propose significant changes to improve its demand response portfolio.

UCAN recommends that the Commission establish interim benchmarks for SDG&E and require SDG&E to meet a minimum TRC cost-effectiveness ratio of at least 0.75 for 2018 program year and of at least 0.90 for 2019 program year

on a portfolio basis.²³¹ ORA finds these benchmarks reasonable.²³² We disagree with UCAN and ORA. The record of this proceeding could not clearly determine why SDG&E's demand response programs and portfolio do not fare as well as those of other utilities' and what specific measures may improve SDG&E's programs and portfolio. Therefore, it may not be meaningful to establish randomly selected quantitative benchmarks at this time. Even though we have not established quantitative benchmarks for SDG&E's program and portfolio cost-effectiveness, we will keep a vigilant oversight of SDG&E's management of its demand response programs and portfolio.

8. Authorized Budgets and Rate Recovery

8.1. Budget Categories and Fund Shifting

As further described below, this Decision modifies the budget categories resulting in a decrease in the number of categories from ten to seven. All previous fund shifting rules remain in effect as adopted in D.12-04-045.

D.12-04-045 established ten budget categories for demand response programs and activities: 1) Reliability Programs; 2) Price Responsive Programs; 3) Demand Response Provider; 4) Emerging and Enabling Technologies; 5) Pilots; 6) Evaluation, Measurement and Verification; 7) Marketing, Education and Outreach; 8) Demand Response Systems Support; and 10) Integrated Programs. Utilities are allowed to shift funding within a category but not between the categories.

²³¹ UCAN Comments on the Proposed Decision, November 29, 2017, at 5-6.

²³² ORA Reply Comments, December 4, 2017, at 2.

In this proceeding, PG&E does not propose any changes to budget categories and requests that fund shifting rules remain the same as described in D.12-04-045.

Demand response programs have gone through changes in the recent years. SCE points to the following changes (1) The Aggregator Managed Portfolio will be discontinued after 2017; (2) The Integrated Demand Side Management funding is approved in the energy efficiency proceeding; (3) Dynamic Pricing budget is requested and approved in general rate case proceedings. Arguing that outdated budget categories lead to confusion and loss of flexibility in shifting funds, SCE proposes to replace the current budget categories with the following:²³³

- Budget Category 1 – Supply-Side Demand Response Program
- Budget Category 2 – Load Modifying Demand Response Program
- Budget Category 3 – Demand Response Auction Mechanism
- Budget Category 4 – Emerging and Enabling Technology Programs
- Budget Category 5 – Pilots
- Budget Category 6 – Marketing, Education, and Outreach
- Budget Category 7 – Portfolio Support (includes EM&V and Systems and Notifications)

Similarly, SDG&E proposes to reduce the budget categories from the current ten categories to six categories by collapsing Reliability, Price Responsive, and Demand Response Service Provider Managed Programs in

²³³ SCE-01 at 15.

order to “achieve maximum flexibility and benefit of budget fund-shifting, to help maintain a vibrant and flexible demand response program portfolio, and minimize the burden and time delays of more frequent Advice Letter requests to the Commission.”²³⁴ SDG&E proposes to have the following six budget categories:

Category 1 – Demand Response Core Programs (former Category 1, 2, 3)

Category 2 – Technology and Pilots (former Category 4, 5, 9)

Category 3 – Evaluation, Measurement & Verification

Category 4 – Demand Response Support Activities
(IT, regulatory policy)

Category 5- Marketing

Category 6 - Special Projects

SDG&E argues that keeping ten budget categories isolates a number of programs into their own category, thereby limiting fund-shifting capability. As an example, SDG&E points out that the existing Category 1- emergency programs include Base Interruptible Program, OBMC, and SLRP. Because OBMC and SLRP are funded through SDG&E’s GRC proceeding, SDG&E claims that it does not have much flexibility to shift funds within this category.²³⁵

Similarly, UCAN recommends reducing budget categories to eight with no category containing more than 25 percent of the portfolio budget. In response, SDG&E points out that PG&E’s Base Interruptible Program makes up 46 percent

²³⁴ SGE-06 at EMD-7.

²³⁵ SGE-06 at EMD-9.

of PG&E's portfolio and SCE's Category 4 exceeds UCAN's suggested 25 percent cap.²³⁶ Therefore, UCAN's proposal may not be applicable to all three Utilities.

We find SCE's request for reducing budget categories due to elimination of certain programs reasonable and applicable to all three utilities. Setting seven budget categories will better reflect current portfolio composition and allow SDG&E more fund-shifting capability within categories, by grouping more than one program under each budget category. These budget categories may be revisited during the mid-cycle review in order to assess their reasonableness. The utilities shall provide information in the mid-cycle review on how their actual spending compares to their budgeted spending for each budget category shown in Attachment 3 of this decision.

Regarding the fund shifting rules, D.09-08-027 provided the Utilities the flexibility to shift funds authorized in the proceeding between demand response programs, so that the Utilities could appropriately respond to unexpected events or changing conditions.²³⁷ However, the Commission also said that major funding changes must be subject to Commission review and public comments.²³⁸ The Commission developed rules that provided the flexibility needed by the Utilities without undermining the Commission's regulatory process.²³⁹ Within each of the budget categories, the Commission allows the Utilities to shift up to 50 percent of a program's funds to another program, with appropriate monthly reporting. If a utility wants to shift more than 50 percent of a program's funds to

²³⁶ SGE-08 at EMD-2.

²³⁷ D.09-08-027 at 211-212.

²³⁸ *Ibid.*

²³⁹ *Ibid.*

a different program within the same budget category, the Commission requires the utility to first submit a Tier 2 Advice Letter.

We reaffirm our findings in D.09-08-027 as well as D.12-04-045 that major changes to the relative funding of specific programs must be subject to thorough regulatory review and party comment. D.12-04-045 states that Utilities may shift funds authorized within a category but shall not shift funds between categories. The Utilities may continue to shift up to 50 percent of a program's fund to another program within the same budget category, with proper monthly reporting, but not between the seven budget categories we adopt in this decision. We continue to require that Utilities submit a Tier 2 AL before shifting more than 50 percent of a program's fund to a different program within the same budget category and follow the directives given in D.12-04-045. We do not have substantiating record to change this policy in this proceeding and therefore maintain the existing funding shifting rules.

8.2. Budget Requests

PG&E, SCE, and SDG&E submitted the following budget requests by program category for 2018-2022, as shown in Table 23. These budget requests cover anticipated administrative and incentive costs related to demand response programs and portfolios. Administrative costs include all costs other than incentives such as ME&O, pilot proposals, demand response operational cost, systems and support cost, measurement and evaluation, program management and overhead costs.

Table 23			
Utility Budget Requests for 2018-2022			
(in thousands)	PG&E	SCE	SDG&E
Category 1 - Supply-Side Demand Response program	\$ 214,266	\$ 51,819	\$ 27,671
Category 2 - Load Modifying Demand Response Program	\$ 11,422	\$ 6,925	\$ 8,096
Category 3 - Demand Response Auction Mechanism and Direct Participation Support	\$ 12,931	\$ 0	\$ 8,037
Category 4 - Emerging and Enabling Technology programs	\$ 27,677	\$ 67,620	\$ 21,383
Category 5 - Pilots	\$ 13,768	\$ 430	\$ 8,429
Category 6 - Marketing, Education, and Outreach (ME&O)	\$ 14,363	\$ 14,337	\$ 4,502
Category 7 - Portfolio Support (includes EM&V, Systems Support, and Notifications)	\$ 54,740	\$ 36,028	\$ 19,819
Total for 2018-2022 Portfolio	\$ 349,165	\$ 177,160	\$ 97,938

No party objected to PG&E's budget request. We find PG&E's requested budget reasonable, as modified by this Decision.

Objections to SCE's budget were raised by (1) ORA (on cost reprogramming of meters and Permanent Load Shifting program); (2) OhmConnect (on the use of ME&O Funds and ratepayer funded incentives for third party programs); and (3) CLECA and the Joint Demand Response Parties (on incentives for Base Interruptible Program-15 and Base Interruptible Program-30). These objections were addressed throughout the Decision. We find SCE's requested budget reasonable, as modified by this Decision.

Objections to SDG&E's cost-effectiveness and requested budget were raised and we made changes to SDG&E's portfolio and programs throughout this decision.

We authorize the following total budgets for the Utilities' 2018-2022 demand response portfolios:

Table 24 Authorized Budgets for 2018-2022 (in millions)		
PG&E	SCE	SDG&E
\$333.272	\$ 751.027 ²⁴⁰	\$ 78.618

The authorized budgets by funding category are appended as Attachment 3.

We reiterate the direction we provided to the Utilities in D.09-08-027 and D.12-04-045 regarding the process for requesting changes or adjustments to the demand response programs and budgets we approve in this decision. Changes such as requests for new demand response programs, increases in the total budget for a demand response program area, or changes to policies specifically adopted in this decision should be made through an Application or a Petition for Modification. We authorize the Utilities to request non-controversial changes to program tariffs and implementation procedures via a Tier 2 Advice Letter. If uncertain whether a particular change is appropriate for review through the Advice Letter process, we encourage the Utilities to consult with Commission Staff before submitting an Advice Letter.

8.3. Rate Recovery

The majority of the Utilities' requests for cost recovery are non-controversial and generally continue the cost recovery approach adopted for earlier demand response program budget cycles. The following discussion presents the utility cost recovery requests, party positions and the Commission adopted positions for cost recovery during the 2018-2022 budget cycle.

²⁴⁰ This includes \$586.514 million in incentives for BIP, AP-I, CBP, SPD, and SDP that SCE included as non-budget line items and the \$177.160 million that SCE included in programmatic costs.

8.3.1. PG&E

PG&E requests authorization to recover up to \$349.2 million in expense and capital costs for the 2018-2022 demand response program cycle. PG&E requests the following:

- Requests the forecast costs and associated revenue requirements for 2018-2022 be deemed reasonable and not be subject to after-the-fact reasonableness review.
- Proposes to continue to true-up the differences between the authorized budgets and actual expenses through the Annual Electric True-Up (AET) Advice Letters process by transferring the balance in the Demand Response Expenditure Balancing Account (DREBA) subaccounts to the Distribution Revenue Adjustment Mechanism.
- Proposes to establish a new subaccount in the DREBA to track costs associated with the Demand Response Auction Mechanism.
- Proposes consolidating the recording and tracking of actual Base Interruptible Program incentives in the Incentives Subaccount in the DREBA.

PG&E adds that its cost recovery proposal assumes that program implementation and cost recovery will commence in the same year. PG&E requests continued recovery of the associated revenue requirements authorized in this Decision through the Distribution Revenue Adjustment Mechanism through electric distribution rates set in the AET advice letters.

8.3.2. SCE

SCE does not propose any major changes to the approved Demand Response Program ratemaking mechanisms. SCE's current ratemaking includes the following accounts:

- Demand Response Program Balancing Account (DRPBA) records the difference between the actual demand response

program cost incurred by SCE and the authorized funding level.

- Base Revenue Requirement Balancing Account (BRRBA) tracks DRAM related costs and is reviewed in ERRA Compliance applications filed on April 1 of each year.
- Purchase Agreement Administrative Cost Balancing Account (PAACBA) records the difference between SCE's actual and authorized administrative costs associated with its AMP program.

SCE seeks the recovery of the authorized demand response program annualized funding through the operation of the Base Revenue Requirement Balancing Account; and recording the difference between the authorized demand response program annualized funding and incurred demand response program expenses in the existing Demand Response Program Balancing Account. SCE states that this way customers pay only for the incurred costs. SCE proposes to retain DRPBA and BRRBA and to eliminate the Purchase Agreement Administrative Cost Balancing Account (PAACBA) due to the elimination of the AMP contracts in 2017.

As previously discussed in Section 5, this Decision directs SCE to record all incentives in the DRPBA, and then record the balances in the BRRBA in order to be in compliance with Commission directives. The remaining cost recovery requests are approved.

8.3.3. SDG&E

SDG&E currently records all programs costs associated with its existing demand response Programs and its current demand response bilateral contracts, including DRAM, in its Advanced Metering and Demand Response Memorandum Account (AMDRMA). SDG&E explains that all authorized demand response programs costs are recorded in AMDRMA which has

two subaccounts: AMDRMA – Distributional and AMDRMA – Generation. Depending on the program’s availability to all customers or only to bundled customers, program costs are recorded in these two subaccounts. Demand response customer incentive payments are recorded in ERRA.

SDG&E requests that authorized demand response program costs related to demand response Operations and Maintenance expenses, capital related costs, customer capacity incentive payments, and all other costs, not recovered through SDG&E’s GRC be recorded in AMDRMA.²⁴¹ This is consistent with D.09-08-027, therefore we approve SDG&E’s request.

8.3.4. Discussion

No party has objected to the Utilities’ rate recovery proposals. We find all proposals, except PG&E’s request discussed below, in compliance with previous decisions and reasonable.

PG&E requests the Commission to determine that forecasted costs and associated revenue for 2018-2022 be considered reasonable and therefore not subject to after-the-fact reasonableness review. PG&E’s request is denied without prejudice.

9. Targeting Demand Response in Constrained Local Capacity Planning Areas and Disadvantaged Communities

Targeting demand response in specific geographic locations is one of the issues identified in the scoping memo.²⁴² In order to develop a record in this matter, the June 30, 2017 Administrative Law Judges’ Ruling directed parties to

²⁴¹ SGE-06 at EMD-6.

²⁴² Scoping Memo and Joint Ruling of Assigned Commissioner and Administrative Law Judges, March 15, 2017 at 4, issue number 8.

respond to a set of questions on the subject.²⁴³ Parties' responses to these questions helped us identify a number of important issues to be explored thoroughly in the short run and long run, including:

- Establishing clear objectives for increasing demand response in specific geographic locations;²⁴⁴
- A clear problem definition, *e.g.* what is being addressed through localized demand response;²⁴⁵
- Defining relevant key terms such as Disadvantaged Communities (DAC);
- Granularity issue, *e.g.*, whether local capacity areas overlap with DACs;²⁴⁶
- Lack of valuation methods associated with more localized needs;²⁴⁷

9.1. Party Positions

Parties in general support targeting demand response in constrained local capacity areas and disadvantaged communities, but they point out that there are a number of details involving program design, marketing efforts, etc., that need to be worked out as this issue has not been addressed before in demand response proceedings. For example, PG&E states that demand response programs are

²⁴³ Joint Demand Response Parties provided comments without waiving objections to this material being outside the scope of a post-hearing brief. Joint Demand Response Parties Opening Brief at 45.

²⁴⁴ PG&E Opening Brief, July 24, 2017, at 56-58; SCE Opening Brief, July 24, 2017, at 40-41; SDG&E Opening Brief, July 24, 2017, at 130-131; and ORA Reply Brief, August 4, 2017, at 7.

²⁴⁵ PG&E Opening Brief, July 24, 2017, at 56.

²⁴⁶ PG&E Opening Brief, July 24, 2017, at 52-53.

²⁴⁷ SCE Opening Brief, July 24, 2017, at 39-40; CLECA Opening Brief, July 24, 2017, at 13; Joint Demand Response Parties Opening Brief, July 24, 2017, at 45-46.

typically designed to meet grid needs, so local resource adequacy requirements target Sub-Load Aggregation Points and local capacity areas which are generally larger than the disadvantaged community census tracts in the CalEnviroScreen.²⁴⁸ From this statement ORA concludes that “current demand response program designs are not conducive to increasing demand response participation in disadvantaged communities in a targeted fashion.”²⁴⁹

SCE recommends that the Commission first define the problem it would like to address, and then undertake a study to gather information on capacity, transmission, and distribution deficiency in local capacity areas at a granular level. SCE contends this will inform options to increase demand response in local capacity areas in conjunction with the efforts underway in the Distributed Resources Plan proceeding, if the Commission intends to target low-income customers or constrained circuits within disadvantaged communities.²⁵⁰ SCE argues that this type of information will help parties develop targeted solutions. ORA supports SCE’s recommendation.²⁵¹

SCE also recommends adopting a consistent definition of DACs across all Commission proceedings.²⁵² Towards that end, SCE supports the definition proposed in the July 1, 2017 Administrative Law Judges’ ruling as it is the definition used in the Integrated Resource Plan proceeding. SCE also points to

²⁴⁸ PG&E Opening Brief, July 24, 2017, at 52-53.

²⁴⁹ ORA Reply Brief, August 4, 2017, at 8.

²⁵⁰ SCE Opening Brief, July 24, 2017, at 39-40.

²⁵¹ ORA Reply Brief, August 4, 2017, at 8.

²⁵² SCE Opening Brief, July 24, 2017, at 40.

missing procedural steps such as the procedure to follow if a certain census tract exits the top quartile after demand response penetration work has begun.²⁵³

SCE points out that marketing efforts related to targeting demand response in specific geographic areas would be different depending on the goal of the project, which could be maximizing savings or increasing participation.²⁵⁴

ORA agrees with other parties that there is need for clarification on the goals and if the issue is considered in this proceeding, discussions should include stakeholders representing disadvantaged communities and environmental justice organizations.²⁵⁵ ORA recommends that the Commission's Energy Division develop a proposal for party comment based on parties' comments in this proceeding and the Commission should provide guidance to the Utilities based on this prior to the mid-cycle review. ORA further suggests that the proposal provide information on how existing programs are performing in local capacity areas, noting a lack of information sufficient to inform strategies to target specific rate-classes, programs or locations.²⁵⁶

ORA also recommends leveraging work being conducted in other proceedings such as Distributed Energy Resources proceeding and Integrated Distributed Energy Resources proceeding. ORA explains that these proceedings are working to create comprehensive tools for identifying location constraints and quantifying locational value and incorporating their work. ORA adds that

²⁵³ SCE Opening Brief, July 24, 2017, at 40.

²⁵⁴ SCE Opening Brief, July 24, 2017, at 40.

²⁵⁵ ORA Reply Brief, August 4, 2017, at 9.

²⁵⁶ ORA Opening Brief, July 24, 2017, at 26.

stakeholder participation will “ensure a fair and reasonable approach for sourcing demand response in disadvantaged communities.”²⁵⁷

On the longer horizon, SCE recommends 1) permitting more flexibility in valuation to include portfolio considerations, should the Demand Response Auction Mechanism pilot become a permanent program, and 2) considering locational incentives for utility programs.²⁵⁸ CLECA recommends updating the interim default G factor in the cost-effectiveness method to “value” local capacity area needs.²⁵⁹

Appreciating the Commission’s interest in targeting demand response in specific geographic locations or communities, the Joint Demand Response Parties note the difficulty in creating a solution, because of 1) the current rules applicable to demand response, 2) the rules that are related to integration of demand response into the CAISO market, and 3) cost-effectiveness.²⁶⁰ According to the Joint Demand Response Parties, the Utilities would need to conduct solicitations in order to incorporate social equity into grid reliability purposes. The Joint Demand Response Parties argue that this effort would require physical specification of areas and proper valuation. The Joint Demand Response Parties suggest offering an incremental incentive to service providers or an exemption from cost-effectiveness methods for resources that target such areas. The Joint Demand Response Parties also point out that the ability to provide services in a

²⁵⁷ ORA Reply Brief, August 4, 2017, at 10.

²⁵⁸ SCE Opening Brief, July 24, 2017, at 38.

²⁵⁹ CLC-01 at 24 and 26.

²⁶⁰ Joint Demand Response Parties Opening Brief, July 24, 2017, at 45.

targeted community would depend on the composition of the customers in that area.²⁶¹

Recommending that marketing materials include a clear “call to action,”²⁶² OhmConnect suggests that the Utilities should market to customers “most likely to perform” in targeted areas, and that this combination could reduce customer acquisition costs. OhmConnect also recommends that the Commission consider enrollment in the CARE (California Alternate Rates for Energy) and FERA (Family Electric Rate Assistance) programs for the purpose of targeting demand response programs in disadvantaged communities.

SDG&E similarly notes that targeting disadvantaged communities is not synonymous with targeting low income households. SDG&E refers to its Locational Demand Response pilot test that showed that targeting customers with different marketing messages is possible and that additional funding would allow for more granular targeting. SDG&E also asserts that demand response programs are transitioning to take advantage of advanced metering and auto-control technologies that will open the door to more customer participation.²⁶³

9.2. Discussion

Based on the parties’ responses and comments, we find that there is not sufficient record to direct the Utilities to make immediate programmatic changes addressing the issue in this decision; however, we find that there is sufficient record and interest to initiate a stakeholder process for purposes of developing

²⁶¹ Joint Demand Response Parties Opening Brief, July 24, 2017, at 46.

²⁶² OhmConnect Opening Brief, July 24, 2017, at 15-16.

²⁶³ SDG&E Opening Brief, July 24, 2017, at 128 – 129.

program changes by: 1) exploring this matter at depth and 2) moving forward with short term activities that advance the work in this proceeding while we lay groundwork for additional long-term policy direction.

We will issue a draft straw proposal in January 2018 providing guidelines for the Utilities to propose pilot projects targeting local capacity areas and DACs. The straw proposal will also specify goals, definitions, and funding parameters for the Commission's consideration in a future decision in 2018. In the first quarter of 2018, the Energy Division shall hold a workshop to discuss the straw proposal. The Energy Division must seek input from organizations representing disadvantaged communities, ratepayer advocates, and other social or environmental justice organizations that may have an interest in furthering the goals of targeting demand response in low income or disadvantaged communities. A subsequent decision issued in this proceeding will adopt a final proposal and provide guidelines to the Utilities to develop and seek approval for proposals based on the guidelines.

We expect this effort be funded mostly through reallocation of the budgets that have already been requested by the utilities. To prevent any adverse impact to the authorized programs and to allow for innovative proposals with big impact in this area, we also authorize a cap of \$2.5 million budget to be allocated for this effort, \$1 million each for PG&E and SCE, and \$.5 million for SDG&E, with ten percent set aside for the evaluation of the effort. We do not have a record to substantiate this budget amount in this proceeding; however, we anticipate that this budget will support invaluable pilot programs that will assist us to shape our policy on targeting demand response in constrained local capacity areas and disadvantaged communities.

10. Coordination Between Proceedings

The Scoping Memo identified three issues where the Commission should ensure coordination between this and other related proceedings: 1) response time requirement on local resource adequacy resources; 2) data access issues; and 3) baseline issues. Parties offered recommendations as to how best the Commission should coordinate efforts for these issues. This Decision discusses the three issues and addresses how the Commission will address and ensure coordination between the appropriate proceedings.

10.1. Response Time Requirement on Local Resource Adequacy Resources

As discussed below, until a resource adequacy requirement is adopted by the Commission in the resource adequacy proceeding, demand response program design with respect to resource adequacy needs will not be changed unless necessary for cost-effectiveness. Future changes adopted by the Commission in the resource adequacy proceeding, which require changes in demand response program design, may be made through a Tier 2 Advice Letter filing by the Utilities or through the 2020 mid-cycle program update, whichever timing is most appropriate.

The majority of this discussion has focused on a 20-minute notification requirement for local resource adequacy resources *proposed* (emphasis added) by the CAISO. The CAISO originally sought to include such a requirement in a Business Practice Manual Proposed Revision Request 854. As explained by the Joint Demand Response Parties, in response to an appeal of the request the CAISO deferred implementation in order to conduct a stakeholder process. The CAISO anticipated the stakeholder process would study and, subject to confirmation of the adequacy of the resources, implement pre-contingency

dispatch resources to effectively resolve contingencies in compliance with applicable reliability standards and the CAISO tariff.”²⁶⁴

Joint Demand Response Parties assert this process is currently active, with the Commission and the CAISO working together to develop the requirements for demand response to meet local resource adequacy – specifically the notification requirement and whether demand response can be either a slow response resource or a fast response resource with 20-minute notification.²⁶⁵ Pointing to PG&E’s and SCE’s proposals to implement programs with a 20-minute notification requirement, the Joint Demand Response Parties contend that neither the Resource Adequacy proceeding nor the CAISO has adopted such a requirement. PG&E also urges the Commission not to order programmatic changes to any demand response program still being evaluated in the resource adequacy proceeding as it would be premature to consider its implementation.²⁶⁶ Additionally, the Joint Demand Response Parties request the Commission to confirm “where changes that impact resource adequacy valuation are to be decided and apply the rules it has adopted and reject proposals for rules that have been denied or are pending.”²⁶⁷

SCE and CLECA also express concern about having differing requirements for demand response resources. SCE encourages the Commission to work

²⁶⁴ Joint Demand Response Parties Opening Brief, July 24, 2017, at 47, footnote 210 citing the CAISO Business Practice Manual Appeals Committee May 13, 2016 Decision on Appeal of Proposed Revision Request 854.

²⁶⁵ *Id.* citing D.16-06-045 at 36.

²⁶⁶ PG&E Opening Brief, July 24, 2017 at 58.

²⁶⁷ Joint Demand Response Parties Opening Comments, July 24, 2017 at 24 and Joint Demand Response Parties Reply Comments, August 4, 2017 at 28-29.

closely with the CAISO to coordinate reliability requirements. CLECA maintains that the CAISO's resource adequacy requirements should be in sync with those of the Commission.²⁶⁸ While arguing that the Commission has not adopted a shortened response time, CLECA acknowledges that if the change is adopted in the future, demand response programs may need to be modified either through the mid-cycle review or an advice letter.²⁶⁹ SCE concedes that the Commission has not adopted a 20-minute notification requirement but calls for a different approach to addressing the issue, stating that it is reasonable for SCE to reflect CAISO requirements in the design and valuation of demand response programs due to the risk of CAISO finding a local capacity area deficient and requiring double procurement.²⁷⁰

Relatedly, the Joint Demand Response Parties and SDG&E reference D.17-06-007 and its directive for continued work on local resource adequacy efforts. SDG&E describes the creation of working groups to ensure "harmonized local resource adequacy rules."²⁷¹ D.17-06-007 directs the Energy Division to coordinate the creation of working groups on the issues of Removal of the Path 26 Constraint, Weather Sensitive Demand Response, Existing Demand Side Load Impacts, and Seasonal Local Resource Adequacy.²⁷²

All parties agree that determinations on resource adequacy issues should be addressed in the resource adequacy proceeding. At this time, the resource

²⁶⁸ CLECA Opening Comments, July 24, 2017 at 13.

²⁶⁹ *Ibid.*

²⁷⁰ SCE Opening Comments, July 24, 2017 at 42.

²⁷¹ SDG&E Opening Brief, July 24, 2017, at 105.

²⁷² D.17-06-007 at Ordering Paragraph 8.

adequacy proceeding has not adopted a 20-minute notification requirement. As noted by the Joint Demand Response Parties, D.17-06-027 confirmed that the Commission was not adopting a 20-minute notification requirement and that additional and coordinated work with CAISO on these issues is necessary.²⁷³ While SCE contends it is reasonable to reflect CAISO requirements in program design, the 20-minute notification is not a requirement. Accordingly, this Decision will not adopt any proposal that includes the 20-minute notification. Furthermore, this Decision will not adopt proposals based on any anticipated requirement, unless the proposal is necessary for appropriate cost-effectiveness of a program, *e.g.*, availability of a program. Parties in this demand response proceeding are encouraged to participate in the working groups established in D.17-06-027 to ensure their points of view are included in the development of resource adequacy policy especially in regard to demand response activities.

Given this is a five-year budget cycle with a 2020 mid-cycle update and adopted resource adequacy requirements may change prior to the 2020 update, the Utilities may file a Tier 2 Advice Letter requesting to make changes to a program or programs in response to a requirement change adopted by the Commission in the Resource Adequacy proceeding. The Tier 2 Advice Letter will allow for the Commission and stakeholders to review the reasonableness of the requested changes.

²⁷³ Joint Demand Response Parties Opening Brief at 48, citing D.17006-027 at 22.

10.2. Data Access Issues

As described below, Resolution E-4868 requires the Utilities to use a click-through authorization process²⁷⁴ to automate the customer consent process for sharing the Utilities' customer data with third-party demand response providers. Furthermore, the resolution also directs the Utilities, alongside stakeholders, to develop a proposal to expand the consent process to other distributed energy resource and energy management providers. As discussed further below, all other data access issues not covered by the click-through authorization process shall be addressed in R.14-08-013.

The Scoping Memo defined the data access issue as a question of whether the Utilities' programs sufficiently address data access issues for the data response providers. Parties discuss multiple data access issues in this category, the predominant issue being the click-through authorization process.

Adopted by the Commission on August 24, 2017, Resolution E-4868²⁷⁵ approves a click-through authorization process. The process streamlines, simplifies, and automates the steps by which customers authorize a utility to share the customer's data with a third-party demand response provider. The process established by Resolution E-4868 applies to all three Utilities. Furthermore, the resolution found that allowing other types of providers, *i.e.*, distributed energy resource providers, to use the authorized processes will

²⁷⁴ The click-through authorization process enables a customer to authorize the Utility to share the customer's data with a third-party Demand Response Provider by completing a consent agreement electronically.

²⁷⁵ D.16-06-008, Ordering Paragraph 9, directed the Utilities to work with parties and the Energy Division to develop a proposal for a streamlined direct participation enrollment process. The Utilities filed Advice Letters recommending the proposal. Resolution E-4868 approved a final proposal.

enable more customers to share their data. Accordingly, the resolution established a Customer Data Access Committee and directed the Utilities to work with the committee to develop a proposal to expand the process to other distributed energy resource and energy management providers. The proposal is to be filed as a new application proceeding in order to provide a broader forum for addressing customer data access issues and alleviate procedural uncertainty.

The Joint Demand Response Parties hone in specifically on the issue of the click-through authorization process, contending that E-4868 should be recognized as governing data access between the Utilities and third-party providers going forward.²⁷⁶ PG&E notes that a great deal of time and effort has been expended by parties in efforts to finalize the click-through authorization process and contends those efforts should not be duplicated in this proceeding. Nevertheless, highlighting that the issue of data access has a broad regulatory impact on how utilities secure customer information, PG&E argues that data access issues should be considered and decided in a proceeding broader in scope than the demand response proceeding, *i.e.* the Integrated Distributed Energy Resources proceeding.²⁷⁷ Conveying similar sentiments, SDG&E, along with OhmConnect, suggests data access issues should be addressed in the Distributed Energy Resources Action Plan and notes that addressing data access issues in this proceeding may exclude other interested distributed energy resource providers who might compete with demand response providers.²⁷⁸

²⁷⁶ Joint Demand Response Parties Opening Briefs, July 24, 2017, at 52.

²⁷⁷ PG&E Opening Briefs, July 24, 2017, at 59-60.

²⁷⁸ SDG&E Opening Briefs, July 24, 2017, at 107-108 and OhmConnect Opening Briefs, July 24, 2017, at 9-10.

Likewise, SCE points to the Integrated Distributed Energy Resources and Distribution Resource Plan proceedings as the appropriate venues to address data access issue.²⁷⁹

This Decision clarifies that Resolution E-4868, which among other things approves the click-through authorization process, applies to all of the Utilities. The Customer Data Access Committee, which was established in E-4868 to expand the process to other distributed energy resource and energy management providers, shall also be the sole forum for developing, for Commission consideration, rules and regulations regarding upgrades or updates to the click-through authorization process. As the Commission previously determined, addressing these issues through an application proceeding noticed to all distributed energy resource providers will ensure a broader forum for addressing the issues regarding the click-through authorization process. However, all other data access issues not covered by the click-through authorization process shall be addressed in R.14-08-013 in order to include other interested distributed energy resource providers who might compete with demand response providers. SDG&E suggested utilizing the Distributed Energy Resources Action Plan, but that is a coordination document not a formal proceeding.

10.3. Baselines

Following adoption of wholesale baselines by the FERC, the Utilities shall file a copy of the FERC tariff in this proceeding. The assigned Administrative Law Judges will issue a Ruling setting a prehearing conference to determine the schedule to consider new and/or alternative baselines and related matters.

²⁷⁹ SCE Opening Briefs, July 24, 2017, at 44.

A baseline is an estimate of the electricity that would have been consumed by a customer in the absence of a demand response event. The baseline is the primary tool for measuring curtailment during a demand response event. A 10 in 10 baseline with a same day adjustment is currently used by the CAISO to calculate settlements for all resources in the CAISO market (wholesale baseline). The Commission also uses a 10 in 10 baseline with a same day adjustment for retail programs and has been using this methodology for commercial and industrial demand response programs since 2012.²⁸⁰ Several parties argue the 10 in 10 baseline does not accurately estimate the load reduction from all customer types.²⁸¹ Providing examples, the Joint Demand Response Parties contend that “a one-size fits all baseline can produce widely varying results, some positive, some negative.”²⁸²

Alternative wholesale baselines have been developed through the CAISO’s Energy Storage Distributed Energy Resource Phase II process, by a Baseline Analysis Working Group. On July 26, 2017, the CAISO Board of Governors approved new baseline methods, which will be used to develop new tariff language to be filed with the Federal Energy Regulatory Commission to adopt three new baselines. The Joint Demand Response Parties, SCE, and SDG&E ask the Commission to consider the alternate baselines, once the FERC has adopted the new tariffs.²⁸³

²⁸⁰ D.12-04-045 at Ordering Paragraph 10.

²⁸¹ *See, for example*, SDG&E Opening Brief, July 24, 2017, at 108.

²⁸² Joint Demand Response Parties Opening Brief, July 24, 2017, at 52-53.

²⁸³ Joint Demand Response Parties Opening Brief, July 24, 2017, at 52, SCE Opening Brief, July 24, 2017, at 45, and SDG&E Opening Brief, July 24, 2017, at 109.

PG&E cautions the Commission that wholesale and retail baselines are not the same and recommends that once FERC approves the wholesale baselines, the Commission should not simply adopt the same baselines for retail settlement.²⁸⁴ PG&E contends there are analytical, financial and technical considerations to be resolved before proposing alternative retail baselines. Furthermore, PG&E states that the issue of baseline may need proceeding-related work. That being said, PG&E recommends the Commission revisit the issue in the mid-cycle review.

This Decision determines that the Commission will address the issue of baselines once the FERC approves the wholesale baselines for the CAISO. Given the complexity that PG&E cautions the Commission about, the issue of baseline is one that may require additional evidence. While PG&E recommends waiting for the mid-cycle review, the mid-cycle review is an advice letter process which does not allow for an evidentiary hearing, if necessary. Hence, following adoption of the wholesale baselines, the Utilities shall file a copy of the FERC tariff in this proceeding. The assigned Administrative Law Judge will set a prehearing conference to determine the schedule to consider new and/or alternative baselines.

11. Reasonableness of Proposals for Post-2019 Demand Response Auction Mechanism Cost Recovery

SDG&E requests funding for the Demand Response Auction Mechanism Pilot (Auction Pilot): SDG&E seeks approval for \$4.778 million for the Auction Pilot, which includes \$1.777 million to cover related costs in 2018-2019 for the next level of implementation. SDG&E urges the Commission to wait to

²⁸⁴ PG&E Opening Brief, July 24, 2017, at 61.

determine whether the auction mechanism should be the main procurement method for supply demand response until sufficient evaluation is complete but also consider permitting the Utilities to bid into the future auctions. SDG&E also requests the Commission to consider a reasonable timeline to complete contract modifications for the auction mechanism, with a focus on introducing a penalty structure to protect the ratepayers.

In D.12-11-025, the Commission resolved several policy questions toward the refinement and adoption of Electric Rules 24 and 32, the third-party direct participation of demand response in the CAISO markets. Subsequently, in A.14-06-001 *et al.*, the Commission authorized funding in D.15-03-042, D.16-03-008, and D.16-06-008 for the Utilities to implement initial and intermediate implementation steps of third-party demand response direct participation to provide day-ahead, real-time and ancillary services in the CAISO market. The Utilities were authorized the funds to develop the capacity to support customer registrations in the CAISO market. Additionally, the Utilities were also approved a separate budget of \$12 million in Resolution E-4868 to implement the Click-Through Authorization process; this budget was originally authorized in Decision 17-06-005. Relatedly, the Commission authorized three pilot auctions referred to as the Demand Response Auction Mechanism Pilot and funding for the related solicitations held in 2015, 2016 and 2017 and the associated contracts for deliveries in 2016, 2017, and 2018/2019.

Determinations regarding the demand response auction mechanism pilot and a permanent auction mechanism, if approved by the Commission, are not in the scope of this proceeding. Furthermore, the Utilities have not been directed at this time to increase the number of customer registrations.

SDG&E requests funding of \$4.78 million but provides no justification as to why the funds are needed or how the funds will be spent. SDG&E only states that the \$1.777 million is needed to cover demand response auction mechanism costs in 2018 and 2019 for the next level of implementation. Again, SDG&E provides no details of what the next level of implementation entails or what the funding will provide.

In comments to the proposed decision, SDG&E clarifies that it requests \$1.777 million for related costs of the Demand Response Auction Mechanism but included a \$3 million expenditure previously approved by the Commission. SDG&E further clarifies that it requested \$278,083 for licensing fee for Rule 32, but that expenditure is addressed in the previous section on Demand Response Systems Support. SDG&E contends that its testimony indicates that it requested an additional \$ 2.981 million to support direct market participation by third parties.²⁸⁵ Explaining that this funding is to provide operational (program management and administrative support) and production support for third party market participants, and Rule 32 information technology related processes.²⁸⁶ SDG&E requests that the Commission allow it to file a Tier 2 Advice Letter to provide additional information on this requested funding. In reply comments to the proposed decision, ORA supported SDG&E's request and urged the Commission to grant this treatment.²⁸⁷

²⁸⁵ SDG&E Opening Comments on Proposed Decision, November 29, 2017 at 8-10. (See also SGE-01 at 50 and Table 13.)

²⁸⁶ *Id.* at 9.

²⁸⁷ ORA Reply Comments on Proposed Decision, December 4, 2017 at 4.

SDG&E's request to reconsider the \$2.981 million is granted. This Decision authorizes the funding contingent upon a reasonable showing by SDG&E in a Tier 2 Advice Letter. Within 60 days of the issuance of this Decision, SDG&E shall file the Tier 2 Advice Letter providing additional justification for the \$2.98 million. Following the evaluation of the demand response auction mechanism, the Commission will address whether it will proceed with a permanent auction mechanism and, if appropriate, will authorize budgets at that time.

12. Integration of Demand Response and Energy Efficiency

On June 26, 2017, the Commission's Energy Division held a workshop to address a proposal for a limited integration of demand response enabling technologies and relevant energy efficiency programs. The June 30, 2017 Administrative Law Judge Ruling directed the parties to respond to a set of questions on the proposal with their opening briefs.

In the three-pronged proposal, Energy Division recommends a limited integration of energy efficiency and demand response through 1) residential heating, ventilation, and air-conditioning (HVAC) controls; 2) non-residential HVAC and lighting controls; and 3) integration of the demand response and energy efficiency potential studies to support analysis under the Integrated Resource Planning (IRP) process. Energy Division proposes repurposing the Integrated Demand-side Management (IDSM) budget to fund this limited integration and to ensure the cost-effectiveness of integrated EE programs are not negatively affected. Energy Division also proposes that the third element be funded through reauthorized demand response research funds and existing energy efficiency Evaluation, Measurement and Verification (EM&V) funds.

12.1. Parties Position

Even though parties have supported the overall goal of the proposal, many parties expressed reservations with its specifics. PG&E does not support the adoption of the straw proposal in its current form arguing that (1) the straw proposal conflicts with the Commission's guidance on energy efficiency business plan filings; (2) differences between anticipated and actual customer participation may affect the benefits of the Element 1 of the proposals; (3) there is risk for stranded investment due to the use of devices other than what is recognized under element 2; and (4) demand response research should be modified to make it compatible and usable for integrated resource planning.²⁸⁸ Both PG&E and SDG&E argue that any directives that emerge from the proposal should be technology neutral and not overly prescriptive in order to incentivize industry innovation.

SCE finds merit in some of the recommendations of the proposal but prefers that the Commission first establish policy goals for the integration of energy efficiency and demand response and a roadmap to achieve them. SCE argues that some projects are redundant and opposes some of the projects because of the focus on specific devices rather than the integration. SCE supports combining the two potential studies as an important first step in being able to move towards a common goal for demand-side management of resources. However, even though SCE is not opposing to the proposed budget, it recommends a reassessment after a detailed scope of work is developed.

SDG&E supports the overall goal, but cautions against being too technology-specific, given the pace of technology developments. In addition,

²⁸⁸ PG&E Opening Brief, July 24, 2017, at 64.

SDG&E does not agree with the use of IDSM funding for this purpose as the funds have already been allocated for local marketing efforts, statewide efforts, and behavioral programs.

The Joint Demand Response Parties find the goals stated by the Staff's proposal sensible, but they disagree with the funding coming mostly from the Integrated Demand Side Management budget since the Joint Demand Response Parties consider the primary motivation of the integration effort as being the energy efficiency automation, not a demand response motivation. In Joint Demand Response Parties' opinion, there should be more balance between the energy efficiency and demand response funding sources.²⁸⁹ The Joint Demand Response Parties request that the Commission not adopt the Staff Proposal's recommendation to combine the demand response and Energy Efficiency Potential Studies or their methodologies or SCE's support of that recommendation. The Joint Demand Response Parties argue that the differences between these resource types make such combinations inappropriate and such an action would delay an actual targeted megawatt goal for demand response.

CLECA is not necessarily opposed to the proposed integration efforts, but is concerned by the prospects of integrating energy efficiency and demand response from the perspective of industrial customers for several reasons including 1) the availability of shareholder incentives for energy efficiency might provide further incentive to favor energy efficiency; 2) demand response helps with grid reliability but there is a lack of proof for energy efficiency; 3) the size of the energy efficiency budget and funding would dominate a combined program;

²⁸⁹ Joint Demand Response Parties Opening Brief, July 24, 2017, at 55-56.

and 4) the difference in experiences in getting utility support for energy efficiency projects and demand response projects.

Some parties find the proposal overly prescriptive and argue that it could lead to stifling innovation or exclude certain technologies.²⁹⁰ Robert Bosch LLC (Bosch) agrees with other parties that any integration plans should not be overly prescriptive and technology-specific. California Efficiency + Demand Management Council is generally supportive of the high-level goals of the Staff Proposal, but also recommends not limiting innovation and not excluding technologies that can communicate rate information to consumers. Similarly, Nest is supportive of the overall goal, but is also concerned about the proposal being too prescriptive and detailed.

12.2. Discussion

We find the parties' comments and thoughts on the subject valuable. On the issue of setting an overall goal, we find merit in SCE's recommendation to establish policy goals for the integration of energy efficiency and demand response and a roadmap to achieve them. However, we think time is of essence and establishing broad policy goals and setting timelines will require resources that neither the Commission nor the parties can afford. Nevertheless, the concurrent filing of both energy efficiency and demand response applications presents an invaluable opportunity for the Commission to explore the limited integration of energy efficiency and demand response activities, as proposed by the Energy Division. The proposal presents a clear objective; and given the limited scope of proposal, the funding request appears to be within reason. In

²⁹⁰ Council Opening Brief, July 24, 2017, at 4; SDG&E Opening Brief, July 24, 2017, at 111.

addition, the lessons learned from this limited integration exercise may help us shape the policy goal of energy efficiency and demand response integration.

Energy Division proposes utilizing the existing statewide integrated demand side management (IDSM) funds for Elements 1 and 2 of the proposal. Pursuant to D.12-11-015, IDSM-related activities are funded through a combination of energy efficiency and demand response funds authorized in the energy efficiency application proceedings. Because IDSM funds can only be authorized in the energy efficiency proceedings, we cannot adopt the proposal in this proceeding. However, should the funding for the straw proposal be approved in A.17-01-013 et al., Applications for Energy Efficiency Rolling Portfolio Business Plans, we support the adoption of the straw proposal and encourage parties to continue their active participation. We also note the synergy between Element 1, with its focus on low income residential customers and Time of Use Rates, and the targeting of disadvantaged communities discussed here in Section 9. We support in particular integration efforts under A.17-01-013 that would complement our pending plans for enabling more demand response participation from disadvantaged communities, including helping them respond to Time of Use rates.

For Integration Element 3 Energy Division recommends reauthorization of the current demand response research funding in A.17-01-012 et al. This funding is currently \$1 million per year. The energy efficiency portion of the proposed energy efficiency-demand response integrated potential study is already funded under energy efficiency evaluation, measurement and verification funds, most recently authorized in D.12-11-015 and extended in D.14-10-046. Staff does not

recommend any further Commission action to provide necessary energy efficiency program funds for this activity.²⁹¹

As explained in the staff proposal, a funding source for demand response research studies, directed by Commission staff, was first authorized in D.12-04-045. The large majority of those funds were spent on the demand response potential study ordered in D.14-12-024. The Commission staff recommends replenishing these funds with a new authorization at the same \$1 million annually level in order to update the demand response potential study.

Staff does not expect the update to the demand response potential study to expend the entire requested budget. However, staff informs us that several demand response research projects which were originally planned had to be set aside in order to prioritize the 2017 demand response potential study. Staff adds that new research projects have also surfaced since the 2017 study was completed and these require additional funding. Staff believes that reauthorizing the demand response research budget at the current \$1 million annual level will provide sufficient funding for the demand response portion of the proposed integrated energy efficiency-demand response potential study, as well as additional research projects. However, staff does not provide details on these new research projects.²⁹²

²⁹¹ Energy Division Straw Proposal on Limited Integration of Energy Efficiency and Demand Response Activities at 17.

²⁹² Energy Division Straw Proposal on Limited Integration of Energy Efficiency and Demand Response Activities at 17.

In this proceeding, parties expressed concern about the level of budget for the potential study. Even though the requested amount will be allocated to support demand response in the best possible way, further work might be needed to determine the projects the requested funding will ultimately support. The 2017 Potential Study was a successful exercise and provided valuable information to the Commission as well as the industry. It is our anticipation that the next potential study to update the 2017 Potential Study should be accomplished at a lower cost. It is also our anticipation that there will be need for additional research to further our goals in this area, *e.g.*, targeting demand response in disadvantaged communities. Therefore, we approve the requested budget of \$5 million over 2018-2022 period, as shown in Table 25, for this effort and authorize the Energy Division Director to share research plans and budget details with the interested parties and public in a workshop in 2018.

Table 25						
Authorized Budget for the Potential Study and Other Research Needs						
	2018	2019	2020	2021	2022	Total
(in thousands)	\$1,000	\$1,000	\$1,000	\$1,000	\$1,000	\$5,000

13. Comments on Proposed Decision

The proposed decision of the Administrative Law Judges 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 CLECA, Joint Demand Response Parties, ORA, OhmConnect, PG&E, SDG&E, SCE, and UCAN on November 29, 2017 and reply comments were filed by these same parties on December 4, 2017. In response, corrections and clarifications are made throughout this Decision. We address certain comments below

In its Opening Comments, referring to its Application and PGE-06, PG&E clarified the budget request for the Direct Participation Electric Rule 24 Operations and Maintenance and Demand Response Integration Policy and Planning programs.²⁹³ Based on the clarification, we remove the contingency on the budget request approval and authorize PG&E's \$21.3 million budget request for these programs. Also in Opening Comments, PG&E requests the Commission address incremental funding required to consider implementation of baselines associated with CAISO's Energy Storage and Distributed Energy Resource Phase 2 initiative.²⁹⁴ In reply comments, ORA contends that no party has had an opportunity to assess or determine the need or reasonableness of this budget request in testimony, hearings or briefs. Due process has not been afforded; thus, a Petition for Modification of this Decision is the appropriate procedural mechanism to address PG&E's requested incremental funding.

14. Categorization and Assignment of Proceeding

This proceeding is categorized as ratesetting. Martha Guzman Aceves is the assigned Commissioner and Kelly A. Hymes and Nilgun Atamturk are the assigned Administrative Law Judges. Pursuant to Public Utilities Code Section 1701.3 and Rule 13.2 of the Commission's Rules of Practice and Procedure, Judge Hymes and Judge Atamturk are designated as the Presiding Officers.

Findings of Fact

1. No party objected to the provisions of the Settlement.

²⁹³ PG&E Opening Comments, November 29, 2017, at 4-5.

²⁹⁴ *Id.* at 12.

2. Given the authorized budget will be lower than what the Settling Parties agree to, the PG&E proposed budget will no longer be applicable and the related provision will not be enforceable.

3. Determination of a cost-effectiveness method is outside the scope of this proceeding.

4. The remaining issues resolved in the Settlement are within the scope of the Settlement.

5. There are no terms within the Settlement that would bind the Commission in the future or violate existing law.

6. The Settlement resolves program-related issues by taking into account diverse interests.

7. Encouraging settlements reduces the expense of litigation, conserves Commission resources and reduces parties' risks.

8. SCE not including the incentives as budget line items led to confusion and misunderstanding in analyzing what SCE actually requested.

9. Auto Demand Response programs do not require cost-effectiveness analyses.

10. Differences in customer base and system load curve do not have as great an impact as they would on a program required to be cost-effective.

11. Different marginal costs and load shapes can require different parameters to be implemented across the Utilities for the same program in order for a program to be cost-effective.

12. Conflicting policy statements have led to confusion about dual participation rules.

13. In D.15-11-042, the Commission stated that non-event based load modifying programs include: Critical Peak Pricing, Real Time Pricing, time of use rates, Permanent Load Shifting, and Peak Day Pricing.

14. There are differing views with respect to whether Critical Peak Pricing and Peak Day Pricing are non-event based load modifying programs.

15. There is insufficient record for the Commission to revise its policies on dual participation in a third-party demand response program and a utility-administered demand response program.

16. D.12-11-025 included a statement that CAISO prohibits registered customers from participating in any other demand response program or having more than one demand response provider.

17. D.12-11-025 was modified by D.13-12-029 to clarify that CAISO limits customers to one Scheduling Coordinator and prohibits registration of a location to both a Reliability Demand Response Resource and a Proxy Demand Resource for the same trading day.

18. PG&E proposes no changes to its Optional Binding Mandatory Curtailment Program or its Scheduled Load Reduction Program.

19. No party opposes PG&E's Optional Binding Mandatory Curtailment Program or its Scheduled Load Reduction Program or the associated budgets.

20. PG&E's requested budget for its PG&E's Optional Binding Mandatory Curtailment Program or its Scheduled Load Reduction Program are under the authorized cap.

21. No party opposes the Optional Binding Mandatory Curtailment Program proposal or budget as requested by SCE.

22. The Rotating Outages program is a statutorily-required program used to control widespread or uncontrolled blackouts.

23. No party opposes SCE's Rotating Outages program recommendations or budget.

24. The Commission wants to ensure demand response portfolios accurately portray the demand response activities.

25. The Scheduled Load Reduction program is legislatively mandated.

26. SCE proposes no changes to the Scheduled Load Reduction program.

27. SCE requests a slightly lower annual budget for the Scheduled Load Reduction program in comparison with the adopted 2017 program budget.

28. No party opposes SCE's program or budget requests for the Scheduled Load Reduction program.

29. No party opposes PG&E's request for its Critical Peak Pricing measurement and evaluation costs or its proposal to transition these costs to its general rate case beginning in 2020.

30. No party opposes SDG&E's request to end its Peak Time Rebate program.

31. Retaining SDG&E's Peak Time Rebate program is duplicative of the efforts in its time-of-use rates.

32. PG&E has reached the 2 percent reliability cap and has a wait list for prospective Base Interruptible Program customers.

33. SCE is close to reaching the 2 percent reliability cap.

34. D.17-10-017 establishes a Supply Side Working Group.

35. Reliability programs are required to be bid into the CAISO market as a supply resource.

36. No party opposes SCE's requested changes to or the proposed incentives for its Agricultural Pumping Interruptible program.

37. PG&E's proposals related to its Base Interruptible Program are addressed in the Settlement.

38. PG&E's requested budget for the Base Interruptible Program, excluding the incentives, is close to the authorized cap.

39. There is increased interest in participating in the aggregator option of SCE's Base Interruptible Program.

40. The benefits of maintaining the aggregator option of SCE's Base Interruptible Program outweighs the low costs of SCE providing the option.

41. Dispatching at the load zone level should allow SCE to combine both directly enrolled resources and aggregated resources that co-exist in the same load zones into the same CAISO resource identifications when bidding into the CAISO market.

42. Dispatching at the load zone level should decrease the number of megawatts not able to be integrated into the CAISO market for SCE's Base Interruptible Program.

43. SCE's proposed changes to the Base Interruptible Program should improve its integration into the CAISO market.

44. The Resource Adequacy proceeding has not implemented the requirement for resources to be subject to a 20-minute notification requirement.

45. It is premature for the Commission to adopt SCE's proposal for new valuations of the 15-minute option and the associated 30-minute option.

46. SDG&E's cost-effectiveness analysis for its Base Interruptible Program resulted in a TRC ratio of 0.8.

47. Improving cost-effectiveness is a reasonable basis for a reduction in program incentives.

48. Joint Demand Response Parties contest SCE's request to change the available hours in the Base Interruptible Program because the hours are different from the hours in PG&E's and SDG&E's program hours.

49. No party opposes PG&E's Smart AC program proposal or requested budget.

50. Allowing a transition to other devices without abandoning the currently used devices is a prudent approach of using ratepayer funds and should minimize costs in the SDG&E Summer Saver Program.

51. Offering additional options in the SDG&E Summer Saver Program should improve customer satisfaction and increase enrollment.

52. SDG&E's cost-effectiveness analysis for its Summer Saver Program results in a TRC ratio of less than 1.0.

53. SCE paid approximately \$68 million to its Summer Discount Plan customers in 2017.

54. SCE plans to decrease Summer Discount Plan customer incentives to \$23.279 million by 2022.

55. SCE is concerned about the effect of decreased Summer Discount Plan customer incentives on customer attrition rates.

56. SCE does not provide any evidence regarding the appropriateness of the reduced Summer Discount Plan customer incentives.

57. SCE plans to replace the Summer Discount Plan with the Peak Time Rebate program.

58. SCE does not anticipate the replacement of Summer Discount Plan to occur within the 2018-2022 Demand Response program cycle.

59. The impact of the increase in the number of event hours on the Summer Discount Plan has not been analyzed.

60. The Capacity Bidding Program offers monthly capacity payments to customers for reducing loads to a pre-determined level and provides energy payments or penalties based on the actual load reduction for a given event.

61. The Capacity Bidding Program is a pay-for-performance program and the penalties are structured to encourage performance.

62. If performance is assessed on a monthly basis rather than an event basis, the incentive to perform may not be as robust.

63. Capacity Bidding Program customers have the option to adjust the pre-determined load level on a monthly basis.

64. The Capacity Bidding Program penalty structure is appropriate given the focus on performance and the ability of customers to revise load on a monthly basis.

65. New alternative baselines may be necessary for the residential option of the Capacity Bidding Program.

66. SDG&E's reasoning for not requesting a residential option for the Capacity Bidding Program is based on undocumented discussions.

67. It is reasonable to require SCE and SDG&E to explore a residential option of the Capacity Bidding Program on a pilot basis.

68. PG&E's loss of load expectations analysis, while not equivalent to a Commission analysis, should not be ignored.

69. There is value in PG&E's efforts to be proactive.

70. Program participants should be afforded more time to adjust to PG&E's proposed Capacity Bidding Program hours to prevent increased customer disenrollments.

71. There is value in increasing the number of options available to aggregators and self-aggregators, which also provides more control over hours of participation and price.

72. PG&E's average annual funding request for the Capacity Bidding Program is \$4.5 million less than that authorized for 2017.

73. In August 2017, SCE filed its advice letter requesting to make changes to its Capacity Bidding Program for program year 2017.

74. Energy Division rejected the advice letter because it was filed so late in the program year.

75. In requesting approval of the 20-minute notification for its 2017 Capacity Bidding Program bridge funding filing, SCE relied upon a proposed CAISO requirement, which was never adopted.

76. Revising the notification timing for SCE's Capacity Bidding Program to 20-minutes is not necessary.

77. SDG&E provides no evidence that real time participation requires a 20-minute notification in the Capacity Bidding Program.

78. Denying the 20-minute notification time leaves SDG&E without a Day-Of option for the Capacity Bidding Program.

79. SDG&E's concept of a Capacity Bidding Program trigger based on price is reasonable.

80. SDG&E provides no information on the method by which it chose the Capacity Bidding Program trigger price.

81. Without additional information on the method by which SDG&E's proposed Capacity Bidding Program price triggers were determined, the Commission cannot determine whether the specific price triggers are appropriate.

82. Some demand response programs eligible for Auto Demand Response incentives are not evaluated for cost-effectiveness.

83. Technology incentive costs are required to be included in the cost-effectiveness analysis of qualifying demand response programs, such as the Capacity Bidding Program

84. Excluding the costs of Auto Demand Response incentives from program analysis may not give us an accurate and complete evaluation of these programs.

85. Auto Demand Response incentives are not included in cost-effectiveness analysis for all programs.

86. Requiring the Utilities to *report* all Auto Demand Response costs associated with all programs that qualify for Auto Demand Response incentives and the cost-effectiveness ratios with and without the Auto Demand Response incentives in subsequent applications should ensure transparency.

87. Providing technology incentives to both third-party customers and utility customers enrolled in supply side programs/activities not subject to cost-effectiveness analysis provides improved customer choice.

88. The Commission has adopted a policy to ensure competitive neutrality.

89. PG&E proposes to expand its Auto Demand Response program to residential customers, which has led to an increase in the requested budget.

90. PG&E's average annual budget request for the Auto Demand Response program is \$0.539 million more than the 2017 authorized amount.

91. No party opposed SCE's Auto Demand Response program proposal.

92. SCE's proposal to align all technology incentives under one program provides additional transparency in the budget.

93. SCE proposes to continue the existing activities for its Emerging Markets and Technologies program for the 2018-2022 demand response program cycle.

94. SCE's proposed average annual budget for its Emerging Markets and Technologies program has more than doubled in comparison with 2017.

95. SCE provides insufficient information regarding the proposed pilots, demonstration, and testing activities for its Emerging Markets and Technologies program.

96. SDG&E proposes to continue its Auto Demand Response program as approved in 2017.

97. SDG&E indicates problems in the past with assurances of load shed in the Technology Deployment Program proposal.

98. The Technology Deployment Program does not have the same safeguards as the Technology Incentive program.

99. Requiring one year of enrollment in an SDG&E program in order to be eligible for the Technology Deployment program incentives is an unnecessarily strict safeguard.

100. PG&E's Supply Side II and Excess Supply Pilot address important issues.

101. PG&E presents reasonable justification for extending its two pilots.

102. PG&E's Supply Side II pilot proposes a mid-cycle review.

103. PG&E prematurely assumes success of its two pilots.

104. SCE's Charge Ready pilot furthers clean air, climate change and load management objectives and complies with the settlement approved by the Commission.

105. SDG&E's Armed Forces and OverGeneration pilots do not have sufficient Evaluation Plans.

106. PG&E's budget request for its evaluation, measurement and verification program is \$690,000 less than what was authorized for program year 2017.

107. No party opposes PG&E's evaluation, measurement and verification proposals or budget request.

108. No party opposes SCE's evaluation, measurement and verification proposals or budget request.

109. SCE's evaluation scheduling should be determined in concert with stakeholders.

110. No party opposes SDG&E's requested budget for its evaluation, measurement, and verification program.

111. SDG&E's proposal for its evaluation, measurement and verification program lacks specific projects identified for research and analytical support.

112. SCE's recommendation to address the issue of a level playing field for marketing, education, and outreach in the Statewide Marketing Education and Outreach proceeding is infeasible.

113. The Statewide Marketing Education and Outreach roadmap filed by the statewide implementer on April 5, 2017 specifically states that because demand response and air conditioner cycling programs are a lower priority and specific to each energy provider, there will be minimal statewide customer engagement messaging on these programs.

114. The websites required by Resolution E-4820 are focused on technology devices not programmatic information.

115. Resolution E-4820 required the Utilities to integrate demand response-related AB 793 offerings into the 2018-2022 demand response portfolio and the Utilities did not amend their application filings to include any budget requests.

116. Replicating the information on the AB 793 websites and placing this information on the Utilities' demand response pages should not require additional funding.

117. PG&E's Marketing, Education, and Outreach average annual funding request is \$346,000 less than was authorized for 2017.

118. No party protested SDG&E's proposal for its Marketing, Education, and Outreach program or its associated budget.

119. SDG&E's Marketing, Education, and Outreach program budget remains relatively flat over the five-year program cycle.

120. SDG&E's 2022 budget request of \$.944 million represents less than a 7 percent increase over the 2017 budget request of \$.885 million.

121. Appropriate marketing and education should increase participation rates and improve cost-effectiveness.

122. PG&E's average annual funding request for its demand response systems support program is less than what was authorized for 2017.

123. Reprogramming SCE's meters now at a cost of \$6.4 million is in the ratepayers' financial interest.

124. Waiting to reprogram SCE's meters could result in additional and unnecessary procurement costs.

125. The costs to reprogram SCE's meters will likely rise due to inflation.

126. The description for SDG&E's demand response systems support program request does not provide sufficient information on each of the listed activities.

127. SDG&E does not provide an estimate for the individual activities in its demand response systems support program.

128. All three Utilities' cost-effectiveness analyses for the permanent load shifting program resulted in TRC ratios of less than 1.0.

129. All three Utilities have experienced low participation in the permanent load shifting program.

130. Over the past four years, few permanent load shifting projects have been started and fewer have been completed.

131. In D.10-12-024, the Commission determined that the relative weight given to any Standard Practice manual test in determining program approval or modification should be determined within the demand response proceeding.

132. Decision 10-12-024 adopted a method for estimating the cost-effectiveness of demand response activities and required the Utilities to use the protocols for all future cost-effectiveness analysis of demand response programs.

133. In order to allow for flexibility and recognize the transition that the demand response market was in, D.12-04-045 deemed programs with a TRC result of 1.0 to be cost-effective, but allowed for an error band of 10 percent, allowing programs with a TRC of at least 0.9 to be deemed cost-effective for the purposes of that proceeding.

134. The Utilities have had sufficient experience with the demand response protocols and have nearly completed the transition of integration with the CAISO markets.

135. Applying a TRC cost-effectiveness ratio of 1.0 can ensure that all regulated demand response programs are cost-effective and quantifiable benefits match or exceed costs.

136. SDG&E's programs and portfolio are not cost-effective.

137. Establishing seven budget categories will better reflect current portfolio composition and allow SDG&E additional fund shifting capability within categories.

138. The current fund shifting rules provide the flexibility needed by the Utilities without undermining the Commission's regulatory process.

139. Major changes to the relative funding of specific programs must be subject to thorough regulatory review and party comment.

140. Aside from the treatment by SCE of its incentives, no party objects the Utilities' rate recovery proposals.

141. There is insufficient record to direct the Utilities to make immediate programmatic changes addressing the issue of targeting demand response in constrained local capacity planning areas and disadvantaged communities.

142. There is sufficient record to initiate a stakeholder process for exploring the targeting of demand response.

143. Determinations on resource adequacy issues should be addressed in the resource adequacy proceeding.

144. The resource adequacy proceeding has not adopted a 20-minute notification requirement.

145. D.17-06-027 in the resource adequacy proceeding confirmed that the Commission was not adopting a 20-minute notification requirement.

146. Resolution E-4868 approved the click through authorization process, which applies to all the Utilities.

147. The customer Data Access Committee was established in E-4868 to expand the click-through process to other distributed energy resource and energy management providers.

148. The distributed energy resources action plan is a coordination document, not a formal proceeding.

149. Alternative wholesale baselines have been developed through the CAISO's Energy Storage Distributed Energy Resources Phase II process, by a Baseline Analysis Working Group.

150. The CAISO Board of Governors approved new baseline methods on July 26, 2017.

151. New CAISO tariff language will be filed with the Federal Energy Regulatory Commission requesting to adopt three new baselines.

152. The issue of baselines may require an evidentiary hearing.

153. The Commission authorized funding in D.15-03-042, D.16-03-008, and D.16-06-008 for the Utilities to implement initial and intermediate implementation steps for third party demand response direct participation to provide day-ahead, real-time and ancillary services in the CAISO market.

154. The Utilities were authorized the funds to develop the capacity to support customers' registrations in the CAISO market.

155. The Utilities were authorized a separate budget of \$12 million in resolution E-4868 to implement the Click-Through Authorization process.

156. The Commission authorized three pilot auctions and funding for the related solicitations held in 2015, 2016, and 2017 and the associated contracts for deliveries in 2016, 2017, and 2018/2019.

157. Determinations regarding the demand response auction mechanism pilot and a permanent auction mechanism, if approved by the Commission, are not in the scope of this proceeding.

158. The utilities have not been directed to increase the number of customer registrations.

159. SDG&E's funding request for Rule 24 and the demand response auction mechanism pilot provides no justification as why the funds are needed or how the funds will be spent.

160. SDG&E provides no details of what the next level of implementation entails or what the funding will provide to ratepayers.

161. The concurrent filing of both energy efficiency and demand response applications presents an opportunity for the Commission to explore limited integration of energy efficiency and demand response activities.

162. The Energy Division proposal presents clear objectives and a reasonable budget.

163. The lessons learned from the integration project may help shape future energy efficiency and demand response integration.

164. Funding for the integration project can only be authorized in the energy efficiency proceeding.

165. Parties expressed concern about the level of budget for the integrated energy efficiency demand response potential study.

166. Further work is needed to determine the projects the requested funding will support.

167. The 2017 Potential Study provided valuable information to the Commission and the demand response industry.

168. The next potential study should be accomplished at a lower cost.

Conclusions of Law

1. The Settlement is reasonable in light of the record, is consistent with the law and prior Commission decisions, and is in the public interest.

2. SCE should present incentive proposals and amounts as budget line amounts in all future demand response portfolio applications.

3. SCE should record all of its demand response incentives in the BRRBA sub-account.

4. The Commission should not require uniform parameters for any demand response program required to be cost-effective, including the Base Interruptible or the Capacity Bidding Programs.

5. The Utilities should work with Parties to determine whether uniform parameters for any utility-administered program across the utilities exist while ensuring cost-effectiveness for that program.

6. The Commission should supplement record on the dual participation issue and provide clarity on the rules by first holding a workshop.

7. PG&E's Optional Binding Mandatory Curtailment program proposal and budget request are reasonable and should be adopted.

8. PG&E's Scheduled Load Reduction Program proposal and budget request are reasonable and should be adopted.

9. SCE's Optional Binding Mandatory Curtailment program proposal and budget request are reasonable and should be adopted.

10. The Rotating Outages program should not be included in future demand response portfolios.

11. SCE's Rotating Outages program and budget request are reasonable and should be adopted.

12. SCE's Scheduled Load Reduction program and budget request are reasonable and should be adopted.

13. PG&E's Critical Peak Pricing program proposal and budget request are reasonable and should be approved.

14. PG&E should transition its Critical Peak Pricing measurement and evaluation costs to its general rate cases in 2020.

15. SDG&E should ramp down and end its Peak Time Rebate program.

16. The Commission should address how to manage the megawatts under the two percent reliability cap through a collaborative process with facilitation by the Energy Division.

17. The Commission should determine whether to maintain the current two percent reliability cap.

18. The Supply Side Working Group should be assigned the task of reviewing the two percent reliability cap.

19. SCE's requested changes to and incentives for its Agricultural Pumping Interruptible program are reasonable and should be adopted.

20. PG&E's Base Interruptible Program proposal and requested budget are reasonable and should be adopted.

21. SCE should continue the aggregator option in the Base Interruptible Program.

22. SCE's proposal to dispatch at the load zone is reasonable and should be adopted.

23. SCE's proposed increased valuation for the 15-minute and 30-minute options of its Base Interruptible Program should not be adopted.

24. A 10 percent decrease in the incentive level for SDG&E's Base Interruptible Program is reasonable given the need to improve cost-effectiveness.

25. PG&E's SmartAC program proposal and budget request are reasonable and should be approved.

26. The proposed changes to SDG&E's Summer Saver Program are reasonable and should be adopted.

27. The Commission should decrease administrative costs in SDG&E's Summer Saver Program to improve the cost-effectiveness of the program.

28. SCE should provide the Commission with a transition plan for replacing SCE's Summer Discount Plan with its Peak Time Rebate.

29. In its 2020 demand response portfolio mid-cycle update, SCE should provide the Commission with a report on the Summer Discount Plan attrition rates and impact of the increase in event hours.

30. Until the impact of the increase in event hours on the Summer Discount Plan can be analyzed, the Commission should not increase the number of event hours for the Peak Time Rebate program.

31. The Commission should review and consider new baselines especially with respect to the residential option of the Capacity Bidding Program.

32. The Commission should require SCE and SDG&E to explore a residential option of the Capacity Bidding Program on a pilot basis.

33. PG&E's proposed Capacity Bidding Program hours (1:00 p.m. to 9:00 p.m.) should be offered on an optional basis.

34. PG&E should offer additional options in its Capacity Bidding Program to aggregators and self-aggregators.

35. SCE's request for a 20 minute notification time for its Capacity Bidding Program should be denied.

36. SDG&E's request to revise its Day-Of option in the Capacity Bidding Program by allowing a two-hour notification time is reasonable and should be adopted.

37. The Commission should not adopt SDG&E's requested price triggers in its Capacity Bidding Program until it can determine whether they are appropriate.

38. The Commission should require the Utilities to provide two sets of cost-effectiveness analyses, one with and one without Auto Demand Response incentives.

39. The Commission should allow customers to access available Auto Demand Response technology incentives, whether they choose to use the technology in a utility-administered or a third-party supply side program not subject to cost-effectiveness.

40. PG&E's Auto Demand Response program proposals and budget are reasonable and should be approved.

41. SCE should align all technology incentives under one program and one budget category.

42. The Commission should approve an Emerging Markets and Technologies budget for SCE based on the 2017 authorized budget.

43. SDG&E's Technology Deployment Program proposals should be adopted.
44. PG&E's Supply Side II and Excess Supply pilots should only be approved for three years; PG&E should provide an evaluation of the pilots in the mid-cycle review.
45. SCE's Charge Ready Pilot should be approved.
46. The Commission should require SDG&E to provide improved Evaluation Plans for its Armed Forces and OverGeneration Pilots.
47. PG&E's budget request for its evaluation, measurement and verification program is reasonable and should be approved.
48. SCE's evaluation scheduling should be determined in concert with parties.
49. SCE's evaluation, measurement and verification program proposals and budgets are reasonable and should be approved.
50. SDG&E's evaluation, measurement and verification program budget should be decreased by 10 percent to improve program and portfolio cost-effectiveness.
51. The Utilities should be required to include information on third-party demand response providers on demand response main web pages.
52. The Commission should not address the issue of an online portal in either A.12-08-07 or through the websites required by E-4820 and AB 793.
53. The Commission should not increase marketing, education, and outreach budgets to replicate the information gathered through Resolution E-4820 and replicated on the Utilities' main demand response web pages.
54. PG&E's marketing, education, and outreach program proposals and budgets are reasonable as modified and should be adopted.
55. SCE's marketing, education, and outreach program proposals and budgets are reasonable as modified and should be adopted.

56. SDG&E's marketing, education, and outreach budget should not be decreased to improve cost-effectiveness.

57. SDG&E's marketing, education and outreach proposals and budgets are reasonable as modified and should be adopted.

58. PG&E's demand response systems support proposals and budgets are reasonable and should be adopted.

59. SCE should be authorized to reprogram its residential and non-residential customer meters now.

60. SCE's demand response systems support budget should be decreased by \$2.5 million.

61. SDG&E's demand response systems support budget should be decreased by 10 percent.

62. The Utilities Permanent Load Shifting program should not be approved in the demand response portfolio in this application or future demand response applications.

63. Utilities have gained sufficient experience in applying the protocols for cost-effectiveness calculations. Solely for the purposes of this proceeding, it is reasonable to eliminate the 10 percent error band and deem programs with 1.0 Total Resource Cost ratio cost-effective.

64. PG&E's demand response programs and portfolio for 2018-2022 have TRC ratios equal to or greater than 1.0 and should be deemed cost-effective.

65. SCE's demand response programs and portfolio for 2018-2022 have TRC ratios equal to or greater than 1.0 and should be deemed cost-effective. SCE's demand response programs and portfolio for 2018-2022 have TRC ratios equal to or greater than 1.0 and should be deemed cost-effective.

66. SDG&E's demand response programs and portfolio for 2018-2022 have TRC ratios less than 1.0 and should be deemed not cost-effective.

67. SCE's request for reducing budget categories from ten to seven due to elimination of certain programs is reasonable.

68. All three Utilities should follow SCE's proposal for budget categories.

69. The Commission should maintain the existing fund shifting rules.

70. All Utilities' proposals for cost recovery should be adopted.

71. The Commission should explore the issue of targeting demand response in constrained local capacity planning areas and disadvantaged communities and initiate a stakeholder process.

72. Determinations on resource adequacy issues should be addressed in the resource adequacy proceeding.

73. Data access issues not covered by the click-through authorization process should be addressed in R.14-08-013.

74. Alternative baselines should not be addressed in the mid-cycle review, but rather, in a future decision in this proceeding.

75. SDG&E's request for additional funding for the demand response auction mechanism pilot should be denied.

76. The Energy Division proposal for a limited energy efficiency demand response integration project should be addressed in the energy efficiency proceeding.

O R D E R

IT IS ORDERED that:

1. This decision approves, as modified, the Settlement Agreement proposed by the Settling Parties (Pacific Gas and Electric Company, California Large

Energy Consumers Association, EnerNOC, Inc., CPower, Inc., EnergyHub, Inc., Ohm Connect, Inc., Electric Motor Werks, Inc., and California Efficiency + Demand Management Council). We adopt all provisions of the Settlement, except provision H, as indicated in Attachments 1 and 2 of this decision.

2. Pursuant to Rule 12.4(c) of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company, California Large Energy Consumers Association, EnerNOC, Inc., CPower, Inc., EnergyHub, Inc., Ohm Connect, Inc., Electric Motor Werks, Inc., and California Efficiency + Demand Management Council, (the Settling Parties) shall, within 15 days after the effective date of this decision, file a letter in this proceeding stating whether they accept the modification adopted in this decision or if they request alternative relief.

3. Southern California Edison Company shall record all demand response incentives in the Demand Response Program Balancing Account (DRPBA) distribution or generation sub-accounts depending on whether the program is available to all customers or bundled customers only. The balances shall be recorded in the Base Revenue Requirement Balancing Account, which will record differences between the forecasted amounts and the actual incentives paid.

4. No later than June 1, 2018, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall begin to work with interested parties to determine whether there are parameters in programs that can be uniform across the three Utilities, while ensuring that cost-effectiveness analyses for the programs result in a 1.0 total resource cost ratio. The Utilities shall report on the discussions and the results of the efforts in their 2020 program update filing.

5. Pacific Gas and Electric Company's (PG&E) Optional Binding Mandatory Curtailment Program and the Scheduled Load Reduction program are approved as requested. PG&E is authorized a five-year budget of \$63,095 to operate the programs.

6. Southern California Edison Company's (SCE) Optional Binding Mandatory Curtailment Program is approved as requested. SCE is authorized a five-year budget of \$15,000 to operate the program.

7. Southern California Edison Company's (SCE) Rotating Outages Program is approved as requested. SCE is authorized a five-year budget of \$400,000 to operate the program.

8. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company are authorized to include all future program and budget requests for the Rotating Outages program in their respective general rate cases beginning with requests for program year 2023.

9. Southern California Edison Company's (SCE) Scheduled Load Reduction program is approved as requested. SCE is authorized a five-year budget of \$15,625 to operate the program.

10. Pacific Gas and Electric Company's (PG&E's) budget request to cover only measurement and evaluation costs of Critical Peak Pricing Programs until 2020 is approved. PG&E is authorized a budget of \$500,000 for program years 2018 and 2019.

11. San Diego Gas & Electric Company's (SDG&E) request to ramp down and retire its Peak Time Rebate program in 2018 is granted. SDG&E is authorized a budget of \$19,594 for program year 2018.

12. The Director of the Energy Division is authorized to hold a workshop no later than February 15, 2018 to begin discussions on managing the current

two percent reliability cap and prioritizing resources under the cap. At the workshop, parties to this proceeding shall each provide a proposal for managing the megawatts under the cap; joint proposals are encouraged. Parties shall work toward a consensus proposal. If a consensus is reached, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities), on behalf of the workshop participants, shall file the proposal in this proceeding. If a consensus is not reached, the Utilities, on behalf of the workshop participants, shall file a report on the workshop discussions and include all proposals and all points of view. The Utilities shall file either the proposal or the workshop report in this proceeding no later than March 30, 2018. Parties shall file comments to the filing no later than April 14, 2018.

13. The Supply Side Working Group, established in Decision (D.) 17-10-017, shall review the two percent reliability cap. In its review of the reliability cap, the Supply Side Working Group shall consider the inputs agreed to in D.10-06-034. The Supply Side Working Group shall file a report on the status of the working group's discussions and/or recommendations with respect to this issue; the report shall be filed in this proceeding no later than March 30, 2018.

14. Southern California Edison Company's (SCE) Agricultural Pumping Interruptible program is approved as requested. SCE is authorized a budget of \$3.34 million to administer the program and an incentive budget cap of \$32 million.

15. Pacific Gas and Electric Company's (PG&E) Base Interruptible Program is approved as requested. PG&E is authorized a five-year budget of \$161.770 million to operate the program. Within 30 days of the issuance of this

Decision, PG&E shall file a Tier One Advice Letter updating the Base Interruptible Program tariff to comply with this Decision.

16. Southern California Edison Company's (SCE) request to discontinue the aggregator option of its Base Interruptible Program is denied. SCE's request to revise its incentive for the 15-minute and 30-minute options is denied. All other requests by SCE for its Base Interruptible Program are adopted. SCE is authorized a budget of \$1.697 million to administer its program and an incentive cap of \$345.776 million. No later than 60 days from the issuance of this Decision, SCE shall file a Tier Two Advice Letter to implement the changes to its Base Interruptible Program tariff, as described and adopted in this Decision.

17. Southern California Edison Company may file a Tier Two Advice Letter to implement further changes to its Base Interruptible Program tariff, if the resource adequacy proceeding adopts changes to the notification requirement for local capacity.

18. San Diego Gas & Electric Company's (SDG&E) Base Interruptible Program is approved as requested. SDG&E is authorized a budget of \$.455 million and an incentive cap of \$4.209 million. Within 30 days of the issuance of this Decision, SDG&E shall file a Tier One Advice Letter updating the Base Interruptible Program tariff to comply with this Decision.

19. Pacific Gas and Electric Company's (PG&E) SmartAC Program is approved as requested. PG&E is authorized a five-year budget of \$31.978 million to operate the program. Within 30 days of the issuance of this Decision, PG&E shall file a Tier One Advice Letter updating the SmartAC program tariff to comply with this Decision.

20. San Diego Gas & Electric Company's (SDG&E) AC Saver Program is approved as requested. SDG&E is authorized a budget of \$11.89 million. Within

30 days of the issuance of this Decision, SDG&E shall file a Tier One Advice Letter updating the AC Saver Program tariff to comply with this Decision.

21. Southern California Edison Company (SCE) Summer Discount Plan and Peak Time Rebate programs are approved with the exception of the increase in event hours for Peak Time Rebate. SCE shall include a report in its 2020 mid-cycle portfolio update on the impact of the hours increase, program attrition rates, and a comparison with anticipated rates. The report shall also include a Summer Discount Plan transition plan that estimates the anticipated increase in Peak Time Rebate customers and the decrease in the Summer Discount Plan customers for 2021-2031. SCE is authorized a budget of \$37.68 million for the Summer Discount Plan and a total incentive cap of \$182.378 million as a contingency plan if the report indicates that the decreased incentives are negatively affecting the program; SCE is also authorized a budget of \$8 million and incentives of \$12.4 million for the Peak Time Rebate Program. Within 30 days of the issuance of this Decision, SCE shall file a Tier One Advice Letter updating the Summer Discount Plan and Peak Time Rebate program tariffs to comply with this Decision.

22. Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) shall each include in their 2020 mid-cycle review a proposal for a one-year residential Capacity Bidding Program pilot in their service territory. SCE is authorized a budget cap of \$1.005 million and SDG&E is authorized a budget cap of \$708,000 to implement the one year pilot. SCE and SDG&E shall work with Pacific Gas and Electric Company and other parties to create a streamlined residential enrollment process for the Capacity Bidding Program.

23. Pacific Gas and Electric Company's (PG&E) request to change its Capacity Bidding Program operating hours from 11:00 a.m. – 7:00 p.m. to 1:00 p.m. – 9:00 p.m. is denied. PG&E shall offer the proposed hours as optional, only. With this modification on default operation hours, PG&E's Capacity Bidding Program is approved as requested. PG&E is authorized a five-year budget of \$20.518 million to operate the program. PG&E shall file a Tier One Advice Letter within 60 days of the issuance of this decision updating the tariff for its Capacity Bidding Program consistent with this Decision.

24. Southern California Edison Company's (SCE) Capacity Bidding Program is approved with one modification. SCE's request for a 20-minute notification time is denied. SCE is authorized a five-year budget of \$1.083 million to implement the Capacity Bidding Program and an incentive cap of \$13.946 million. SCE shall file a Tier One Advice Letter within 60 days of the issuance of this decision updating the tariff for its Capacity Bidding Program consistent with this Decision.

25. San Diego Gas & Electric Company's (SDG&E) Capacity Bidding Program is adopted as modified herein. SDG&E shall not implement a 20-minute notification time, shall revise its Day-Of option to have a two-hour notification time, and shall not implement its proposed price triggers at this time. SDG&E is authorized a five-year budget of \$10.535 million. SDG&E shall file a Tier One Advice Letter within 60 days of the issuance of this decision updating the tariff for its Capacity Bidding Program consistent with this Decision.

26. Within 30 days of the issuance of this Decision, San Diego Gas & Electric Company (SDG&E) shall file a proposal in this proceeding describing the method used to determine its Capacity Bidding Program price triggers. No later

than 14 days after the filing of the proposal, parties shall file comments on the proposal.

27. In future required cost-effectiveness analyses, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall report the Auto Demand Response costs associated with all programs that qualify for Auto Demand Response incentives and their cost-effectiveness ratios with and without the Auto Demand Response incentives and shall clearly indicate the total Auto Demand Response incentives excluded from portfolio cost-effectiveness analysis and the costs associated with customers participating in each program qualifying for Auto Demand Response incentives.

28. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall provide Auto Demand Response technology incentives to participants of any supply side demand response programs/activities not required to be analyzed for cost-effectiveness.

29. No later than 60 days from the issuance of this decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file a set of draft guidelines to implement the Auto Demand Response device policy adopted in Ordering Paragraph 29. The draft guidelines will be used during a workshop to discuss the undefined aspects for this policy including: eligibility frequency and eligible devices.

30. Pacific Gas and Electric Company's (PG&E) Automatic Demand Response Program is approved as amended. PG&E shall provide Auto Demand Response technology incentives to participants of any supply side demand response program/activity not required to be analyzed for cost-effectiveness. PG&E is authorized a five-year budget of \$20.446 million to operate the program.

31. Pacific Gas and Electric Company's (PG&E) Demand Response Emerging Technology Program is approved as requested. PG&E is authorized a five-year budget of \$7.230 million to operate the program.

32. Southern California Edison Company's (SCE) Automated Demand Response Technology Incentive Program and Programmable Communicating Thermostat Incentive Program are approved as amended. SCE shall provide Auto Demand Response technology incentives to participants of any supply side demand response program/activity not required to be analyzed for cost-effectiveness. SCE is authorized a five-year budget of \$43.639 million.

33. Southern California Edison Company's (SCE) Emerging Markets and Technologies program is approved as requested. SCE is authorized a five-year budget of \$14.61 million. SCE may provide additional information on this program in the 2020 mid-cycle update. If SCE provides sufficient additional information, SCE may be granted additional funding up to \$4.715 million each year, based on the amount requested for 2018 in this application.

34. San Diego Gas & Electric Company's (SDG&E) Auto Demand Response program is approved as amended. SDG&E shall provide Auto Demand Response technology incentives to participants of any supply side demand response program/activity not required to be analyzed for cost-effectiveness. SDG&E is authorized a budget of \$11.967 million.

35. San Diego Gas & Electric Company's (SDG&E) Technology Deployment Program is approved. SDG&E shall require customers to enroll in any supply side demand response program, either SDG&E-administered or a third-party program. SDG&E is authorized a budget of \$3.794 million.

36. San Diego Gas & Electric Company's (SDG&E) Emerging Technology program is approved as modified; SDG&E shall not implement its Permanent

Load Shifting program. SDG&E is authorized a budget of \$3.483 million, a decrease of 10 percent to address the cost-effectiveness analysis results. SDG&E may use 2017-authorized Permanent Load Shifting incentives in 2018 for projects already in progress.

37. Pacific Gas and Electric Company's (PG&E) Supply Side Pilot Program is approved for 2018-2020. PG&E is authorized a three-year budget of \$6.338 million to operate the program. In the mid-cycle review that will occur in 2020, should the Energy Division determine that the objectives of the pilots are not met and they should still be pursued, then the Energy Division shall authorize funding up to the original requested budget for years 2021 and 2022. PG&E is authorized to continue to use a two-way balancing account for the incentive portion of the pilot's budget.

38. Pacific Gas and Electric Company's (PG&E) Excess Supply Pilot Program is approved for 2018-2020. PG&E is authorized a three-year budget of \$1.813 million to operate the program. In the mid-cycle review that will occur in 2020, should the Energy Division determine that the objectives of the pilots are not met and they should still be pursued, then the Energy Division shall authorize funding up to the original requested budget for years 2021 and 2022. PG&E is authorized to continue to use a two-way balancing account for the incentive portion of the pilot's budget.

39. Pacific Gas and Electric Company shall file a Tier 1 Advice Letter no later than 90 days from the issuance of the Decision containing evaluation, measurement and verification metrics based on input by the Demand Response Measurement and Evaluation Committee for both Supply Side II and Excess Supply Side pilots.

40. Southern California Edison Company's (SCE) Charge Ready Pilot is approved as requested. SCE is authorized a two-year budget of \$429,953.

41. San Diego Gas & Electric Company's (SDG&E) Armed Forces Pilot is approved with modification. SDG&E shall work with the Office of Ratepayer Advocates to develop a more detailed evaluation plan with metrics to quantify the objectives in Table 13 of this Decision, and the additional objective of testing the proposed incentive level and penalty structure. SDG&E shall file a Tier One Advice Letter no later than 90 days from the issuance of this Decision providing the agreed upon Evaluation Plan. The Evaluation and recommendations shall be submitted with the mid-cycle update in 2020. If the Evaluation indicates success based upon results of the agreed upon metrics, SDG&E may be authorized a two-year budget (2021-2022) up to the amount requested in this application. SDG&E is authorized a three-year budget of \$2.507 million for its Armed Forces Pilot.

42. San Diego Gas & Electric Company's (SDG&E) Over-Generation pilot is approved with modification. SDG&E shall work with the Office of Ratepayer Advocates to develop a more detailed Evaluation Plan with metrics to quantify the objectives in Table 14 of this Decision. SDG&E shall file a Tier One Advice Letter no later than 90 days from the issuance of this Decision providing the agreed upon Evaluation Plan. The Evaluation and recommendations shall be submitted with the mid-cycle update in 2020. If the Evaluation indicates success based upon results of the agreed upon metrics, SDG&E may be authorized a two-year budget (2021-2022) up to the amount requested in this application. SDG&E is authorized a three-year budget of \$2.148 million for its Over-Generation Pilot.

43. Pacific Gas and Electric Company's (PG&E) Demand Response Measurement and Evaluation Program is approved as requested. PG&E is authorized a five-year budget of \$12.902 million to operate the program.

44. Southern California Edison Company's (SCE) Evaluation, Measurement and Verification Program is approved as requested. No later than April 30, 2018, SCE shall hold a meeting with the parties of this proceeding to discuss the evaluation planning process and develop a five-year evaluation, measurement and verification activity schedule. No later than June 1, 2018, SCE shall file the five-year schedule via a Tier One Advice Letter. SCE is authorized a five-year budget of \$6.090 million.

45. San Diego Gas & Electric Company's (SDG&E) Evaluation, Measurement and Verification Program is approved as requested. SDG&E is authorized a five-year budget of \$5.795 million.

46. No later than March 30, 2018, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) shall ensure that the names, logos, web addresses, and 2-sentence program descriptions of each qualified third-party demand response provider operating in their service territory are provided on the main home page of each utility's demand response home page. A qualified third-party demand response provider shall have executed a demand response contract with the utility; the contract can either be for providing demand response aggregator services or to provide demand response through the demand response auction mechanism. The Utilities are authorized to post a disclaimer stating that the information has been provided by the third-party provider and the utility is not responsible for the content of the information; the Utilities shall each work with the Energy Division to develop a final disclaimer with standardized language. No later than

60 days of the issuance of this Decision, the Utilities shall each file a Tier One Advice Letter describing how they will inform customers about the existence of the main demand response web page described herein.

47. Pacific Gas and Electric Company's (PG&E) Marketing, Education and Outreach Program is approved, as modified in this Decision. PG&E is authorized a five-year budget of \$14.204 million to operate the program.

48. Southern California Edison Company's (SCE) Marketing, Education and Outreach Program is approved. SCE is authorized a five-year budget of \$14.277 million to operate the program.

49. San Diego Gas & Electric Company's (PG&E) Marketing, Education and Outreach Program is approved. SDG&E is authorized a five-year budget of \$4.502 million to operate the program.

50. Pacific Gas and Electric Company's (PG&E) Demand Response Systems Support Program is approved. PG&E is authorized a five-year budget of \$54.769 million to support the program.

51. San Diego Gas and Electric Company's (SDG&E) Demand Response Systems Support Program is approved. SDG&E is authorized a five-year budget of \$7.947 million to implement this program.

52. Southern California Edison Company's (SCE) Demand Response Systems Support Program is approved. SCE is authorized a five-year budget of \$29.21 million to implement this program.

53. San Diego Gas and Electric Company (SDG&E) shall (1) reduce its administrative budget by ten percent as indicated throughout the ordering paragraphs of this Decision; (2) meet with Energy Division on a quarterly basis to discuss its progress in improving the cost effectiveness of its programs and portfolios, and (3) file Tier One Advice Letters in June 2019 and 2020

demonstrating the costs of its programs administered the previous year as well as the cost-effectiveness of these programs, and include the following additional information: Progress reports on all of the 2017 improvements SDG&E is in the process of implementing or has implemented, including a description of the improvement, its implementation status, and how it will impact or has impacted the Total Resource Cost (TRC) ratios; Report on the new changes and improvements to SDG&E's portfolio to improve the cost-effectiveness, including description of the programmatic change, timeline for implementation, and how it will impact the TRC ratio of the affected program; and Updated cost-effectiveness ratios based on changing conditions, *e.g.* programmatic changes, reductions in spending, market conditions, etc.

54. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall organize their demand response activities within the following budget categories: 1) Supply-Side Demand Response Program; 2) Load Modifying Demand Response Program; 3) Demand Response Auction Mechanism; 4) Emerging and Enabling Technology programs; 5) Pilots; 6) Marketing, Education, and Outreach; and 7) Portfolio Support (includes Evaluation Measurement & Verification and Systems & Notifications). PG&E, SDG&E, and SCE shall provide information in the mid-cycle review on how their actual spending compares to their budgeted spending for each budget category.

55. Pacific Gas and Electric Company shall file Tier 1 Advice Letter no later than 30 days after the issuance of the decision to: (1) revise the Distribution Revenue Adjustment Mechanism to remove recording BIP incentives since those amounts will now be consolidated with the recording and tracking of incentives in the Incentives Subaccount in the Demand Response Expenditures Balancing

Account (DREBA), and (2) establish a Demand Response Auction Mechanism Sub-account in the DREBA.

56. San Diego Gas & Electric Company (SDG&E) is authorized a budget of \$2.98 for costs related to operations of third party direct participation; the funding is contingent upon a reasonable showing by SDG&E in a Tier 2 Advice Letter. Within 60 days of the issuance of this Decision, SDG&E shall file the Tier 2 Advice Letter providing additional justification for the \$2.98 million.

57. The Director of the Energy Division is authorized to hold a workshop in the first quarter of 2018 to discuss a draft straw proposal on the subject of targeting demand response in constrained local capacity areas and disadvantaged communities.

58. Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company (the Utilities) are authorized a three-year budget of \$2.5 million for pilot programs, \$1 million each for PG&E and SCE, and \$.5 million for SDG&E, targeting demand response in constrained local capacity areas and disadvantaged communities. Ten percent of this budget shall be used to evaluate the success of the pilots. The specifics of the pilots will be determined in a future decision.

59. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) are authorized a five-year budget of \$5 million for updates to the Demand Response Potential Study and other research projects, \$2 million each for PG&E and SCE, and \$1 million for SDG&E.

60. Unless indicated otherwise in this Decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison

Company shall file Tier One Advice Letters to update demand response program tariffs to comply with this Decision.

61. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall meet with the Commission's Energy Division no less than six months prior to the filing of the 2023-2027 Demand Response Portfolio Applications due on November 1, 2021. The purpose of the meeting is to discuss the 2023-2027 Applications to ensure the Utilities provide sufficient information to analyze the Applications, in an agreed-upon format.

62. Application (A.) 17-01-012, A.17-01-018 , and A.17-01-019 remain open.

This order is effective today.

Dated December 14, 2017, at San Francisco, California.

MICHAEL PICKER

President

CARLA J. PETERMAN

LIANE M. RANDOLPH

MARTHA GUZMAN ACEVES

CLIFFORD RECHTSCHAFFEN

Commissioners

ATTACHMENT 1 - Settlement Agreement of Pacific Gas and Electric Company, California Large Energy Consumers Association, Enernoc, Inc., Cpower, Inc., Energyhub, Inc., Ohmconnect, Inc., Electric Motor Werks, Inc., and California Efficiency + Demand Management Council On Specified Issues in Application 17-01-012.

ATTACHMENT 2 - Amendment 1 to Correct Error Settlement Agreement of Pacific Gas and Electric Company, California Large Energy Consumers Association, Enernoc, Inc., Cpower, Inc., Energyhub, Inc., Ohmconnect, Inc., Electric Motor Werks, Inc., And California Efficiency + Demand Management Council on Specified Issues in Application 17-01-012.

ATTACHMENT 3 - 2018 - 2022 Demand Response Program Budgets

PG&E 2018-2022 Authorized Demand Response Budget						
(in thousands)	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>Total</u>
Category 1 – Supply-Side demand response program						
AC Cycling: Smart AC	\$ 5,759	\$ 5,759	\$ 5,759	\$ 5,759	\$ 5,759	\$ 28,794
<i>Smart AC Incentives</i>	\$ 637	\$ 637	\$ 637	\$ 637	\$ 637	\$ 3,184
Base Interruptible Program (BIP)	\$ 566	\$ 566	\$ 5	\$ 566	\$ 566	\$ 2,832
<i>BIP Incentives</i>	\$ 31,788	\$ 31,788	\$ 31,788	\$ 31,788	\$ 31,788	\$ 158,938
Capacity Bidding Program (CBP)	\$ 664	\$ 664	\$ 664	\$ 664	\$ 664	\$ 3,321
<i>CBP Incentives</i>	\$ 3,439	\$ 3,439	\$ 3,439	\$ 3,439	\$ 3,439	\$ 17,197
Category 1 Total	\$ 42,853	\$ 42,853	\$ 42,853	\$ 42,853	\$ 42,853	\$ 214,266
Category 2 – Load Modifying demand response Program						
Optional Binding Mandatory Curtailment (OBMC) and Scheduled Load Reduction Program (SLRP)	\$ 12	\$ 12	\$ 13	\$ 13	\$ 13	\$ 63
Permanent Load Shifting (PLS) <i>Eliminated</i>	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Category 2 Total	\$ 12	\$ 12	\$ 13	\$ 13	\$ 13	\$ 63
Category 3 – Demand Response Auction Mechanism (DRAM) and Direct Participation Electric Rule 24/32						
DRAM	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Direct Participation Electric Rule 24 Operation & Maintenance	\$ 2,439	\$ 2,511	\$ 2,584	\$ 2,659	\$ 2,737	\$ 12,931
Category 3 Total	\$ 2,439	\$ 2,511	\$ 2,584	\$ 2,659	\$ 2,737	\$ 12,931
Category 4 – Emerging and Enabling Technology programs						
AutoDR	\$ 4,006	\$ 4,050	\$ 4,090	\$ 4,130	\$ 4,171	\$ 20,446
DR Emerging Technology	\$ 1,380	\$ 1,416	\$ 1,446	\$ 1,478	\$ 1,510	\$ 7,230
Category 4 Total	\$ 5,386	\$ 5,466	\$ 5,536	\$ 5,607	\$ 5,681	\$ 27,677

PG&E 2018-2022 Authorized Demand Response Budget						
Category 5 – Pilots						
Supply Side Pilot	\$ 2,083	\$ 2,114	\$ 2,141	\$ 0	\$ 0	\$ 6,338
Excess Supply	\$ 596	\$ 605	\$ 612	\$ 0	\$ 0	\$ 1,813
Local Capacity Planning Areas and Disadvantaged Communities Pilot	\$ 0	\$ 250	\$ 250	\$ 250	\$ 250	\$ 1,000
Category 5 Total	\$ 2,679	\$ 2,968	\$ 3,004	\$ 250	\$ 250	\$ 9,150
Category 6 – Marketing, Education, and Outreach (ME&O)						
DR Core Marketing & Outreach	\$ 2,484	\$ 2,547	\$ 2,603	\$ 2,660	\$ 2,719	\$ 13,013
Education and Training	\$ 252	\$ 262	\$ 270	\$ 279	\$ 288	\$ 1,350
Marketing for PLS <i>Eliminated</i>	(\$ 158)	(\$ 158)	(\$ 158)	(\$ 158)	(\$ 158)	(\$ 792)
Category 6 Total	\$ 2,577	\$ 2,650	\$ 2,715	\$ 2,780	\$ 2,848	\$ 13,571
Category 7 – Portfolio Support (includes EM&V, Systems Support, and Notifications)						
DR Measurement and Evaluation Committee (DRMEC)	\$ 3,233	\$ 3,262	\$ 2,133	\$ 2,136	\$ 2,138	\$ 12,902
EM&V for PLS <i>Eliminated</i>	(\$ 225)	(\$ 225)	(\$ 225)	(\$ 225)	(\$ 225)	(\$ 1,125)
DR Integration Policy & Planning	\$ 1,576	\$ 1,629	\$ 1,677	\$ 1,727	\$ 1,778	\$ 8,386
Support for Market Activities	\$ 3,791	\$ 2,331	\$ 2,398	\$ 2,467	\$ 2,538	\$ 13,524
Support for Retail & Customer-Facing Activities	\$ 4,235	\$ 3,794	\$ 3,879	\$ 3,966	\$ 4,055	\$ 19,928
DR Potential Study	\$ 400	\$ 400	\$ 400	\$ 400	\$ 400	\$ 2,000
Category 7 Total	\$ 13,009	\$ 11,190	\$ 10,262	\$ 10,470	\$ 10,684	\$ 55,615
Total Authorized in 2018-2022 Portfolio for PG&E (in thousands)	\$ 68,955	\$ 67,651	\$ 66,966	\$ 64,634	\$ 65,067	\$ 333,272

SCE 2018-2022 Authorized Demand Response Budget						
(in thousands)	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>Total</u>
Category 1 – Supply-Side demand response program						
Agricultural & Pumping Interruptible (API)	\$ 1,767	\$ 371	\$ 395	\$ 400	\$ 407	\$ 3,340
<i>API Incentives</i>	\$ 6,615	\$ 6,501	\$ 6,398	\$ 6,295	\$ 6,193	\$ 32,002
Base Interruptible Program (BIP)	\$ 312	\$ 326	\$ 341	\$ 352	\$ 366	\$ 1,697
<i>BIP Incentives</i>	\$ 71,973	\$ 70,487	\$ 69,111	\$ 67,735	\$ 66,471	\$ 345,776
Capacity Bidding Program (CBP)	\$ 201	\$ 209	\$ 218	\$ 224	\$ 231	\$ 1,083
<i>CBP Incentives</i>	\$ 2,789	\$ 2,789	\$ 2,789	\$ 2,789	\$ 2,789	\$ 13,946
Save Power Days (SPD)	\$ 1,143	\$ 1,365	\$ 1,612	\$ 1,832	\$ 2,066	\$ 8,019
<i>SPD Incentives</i>	\$ 1,688	\$ 2,085	\$ 2,482	\$ 2,880	\$ 3,277	\$ 12,412
Summer Discount Program (SDP)	\$ 7,693	\$ 7,624	\$ 7,562	\$ 7,430	\$ 7,372	\$ 37,680
<i>SDP Incentives</i>	\$ 51,630	\$ 42,667	\$ 35,625	\$ 29,177	\$ 23,279	\$ 182,378
Category 1 Total	\$ 145,811	\$ 134,424	\$ 126,534	\$ 119,115	\$ 112,450	\$ 638,334
Category 2 – Load Modifying demand response Program						
Optional Binding Mandatory Curtailment (OBMC)	\$ 3	\$ 3	\$ 3	\$ 3	\$ 3	\$ 15
Rotating Outages	\$ 80	\$ 80	\$ 80	\$ 80	\$ 80	\$ 400
Scheduled Load Reduction Program (SLRP)	\$ 3	\$ 3	\$ 3	\$ 3	\$ 3	\$ 16
Permanent Load Shifting (PLS) <i>Eliminated</i>	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Category 2 Total	\$ 86	\$ 86	\$ 86	\$ 86	\$ 86	\$ 431

SCE 2018-2022 Authorized Demand Response Budget						
Category 3 – Demand Response Auction Mechanism (DRAM) and Direct Participation Electric Rule 24/32						
Demand Response Auction Mechanism (DRAM)	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Category 3 Total	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Category 4 – Emerging and Enabling Technology programs						
Emerging Markets and Technology	\$ 2,922	\$ 2,922	\$ 2,922	\$ 2,922	\$ 2,922	\$ 14,610
<i>Technology Incentives</i>	\$ 11,886	\$ 7,829	\$ 7,952	\$ 7,959	\$ 8,013	\$ 43,639
Category 4 Total	\$ 14,808	\$ 10,751	\$ 10,874	\$ 10,881	\$ 10,935	\$ 58,249
Category 5 – Pilots						
Charge Ready Pilot	\$ 171	\$ 259	\$ 0	\$ 0	\$ 0	\$ 430
Constrained Local Capacity Planning Areas and Disadvantaged Communities Pilot	\$ 0	\$ 250	\$ 250	\$ 250	\$ 250	\$ 1,000
CBP Residential Pilot	\$ 1,005					\$ 1,005
Category 5 Total	\$ 1,176	\$ 509	\$ 250	\$ 250	\$ 250	\$ 2,435
Category 6 – Marketing, Education, and Outreach (ME&O)						
Other Local Marketing	\$ 2,889	\$ 2,849	\$ 2,850	\$ 2,866	\$ 2,882	\$ 14,337
Marketing for PLS <i>Eliminated</i>	(\$ 12)	(\$ 12)	(\$ 12)	(\$ 12)	(\$ 12)	(\$ 60)
Category 6 Total	\$ 2,877	\$ 2,837	\$ 2,838	\$ 2,854	\$ 2,870	\$ 14,277

SCE 2018-2022 Authorized Demand Response Budget						
Category 7 – Portfolio Support (includes EM&V, Systems Support, and Notifications)						
DR Systems & Technology Support Total including (a) - (e)	\$ 4,828	\$ 9,921	\$ 4,328	\$ 5,696	\$ 4,437	\$ 29,210
<i>a) Meter Reprogramming</i>	\$ 0	\$ 5,120	\$ 0	\$ 1,280	\$ 0	\$ 6,400
<i>b) Integrate Automation</i>	\$ 460	\$ 161	\$ 157	\$ 227	\$ 157	\$ 1,163
<i>c) Hosting & Licensing</i>	\$ 1,898	\$ 1,898	\$ 1,898	\$ 1,898	\$ 1,898	\$ 9,490
<i>d) System Enhancements</i>	\$ 1,007	\$ 807	\$ 507	\$ 407	\$ 507	\$ 3,235
<i>e) SCE Labor Costs</i>	\$ 1,463	\$ 1,935	\$ 1,766	\$ 1,884	\$ 1,875	\$ 8,922
Evaluation, Measurement & Verification (EM&V)	\$ 1,323	\$ 1,313	\$ 1,353	\$ 1,393	\$ 1,435	\$ 6,817
EM&V for PLS Eliminated	(\$ 137)	(\$ 141)	(\$ 145)	(\$ 150)	(\$ 154)	(\$ 727)
DR Potential Study	\$ 400	\$ 400	\$ 400	\$ 400	\$ 400	\$ 2,000
Category 7 Total	\$ 6,414	\$ 11,493	\$ 5,936	\$ 7,340	\$ 6,118	\$ 37,301
Total Authorized in 2018-2022 Portfolio for SCE	\$ 171,173	\$ 160,101	\$ 146,518	\$ 140,526	\$ 132,710	\$ 751,027

SDG&E 2018-2022 Authorized Demand Response Budget

SDG&E 2018-2022 Authorized Demand Response Budget							
(in thousands)	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>Total W/O Reduction</u>	<u>Total WITH Reduction²⁹⁵</u>
Category 1 – Supply-Side demand response program							
AC Saver Day-Ahead	\$ 173	\$ 177	\$ 166	\$ 179	\$ 183	\$ 879	\$ 791
<i>AC Saver Day-Ahead Incentives</i>	\$ 312	\$ 352	\$ 405	\$ 471	\$ 539	\$ 2,078	\$ 2,078
AC Saver Day-Of	\$ 677	\$ 698	\$ 698	\$ 633	\$ 637	\$ 3,343	\$ 3,009
<i>AC Saver Day-Of Incentives</i>	\$ 1,336	\$ 1,256	\$ 1,184	\$ 1,118	\$ 1,118	\$ 6,012	\$ 6,012
Base Interruptible Program (BIP)	\$ 96	\$ 98	\$ 101	\$ 104	\$ 107	\$ 506	\$ 455
<i>BIP Incentive</i>	\$ 847	\$ 845	\$ 842	\$ 839	\$ 836	\$ 4,209	\$ 4,209
Capacity Bidding Program (CBP)	\$ 194	\$ 199	\$ 163	\$ 168	\$ 149	\$ 873	\$ 785
<i>CBP Incentive</i>	\$ 1,990	\$ 1,890	\$ 1,990	\$ 1,890	\$ 1,990	\$ 9,750	\$ 9,750
Peak Time Rebate (PTR)	\$ 22	\$ 0	\$ 0	\$ 0	\$ 0	\$ 22	\$ 20
Category 1 Total	\$ 5,648	\$ 5,515	\$ 5,548	\$ 5,402	\$ 5,559	\$ 27,671	\$ 27,109
Category 2 – Load Modifying demand response Program							
Optional Binding Mandatory Curtailment (OBMC) and Scheduled Load Reduction Program (SLRP)	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0

²⁹⁵ SDG&E budgets were reduced across all categories except Category 1, Supply Side Program Incentives, Marketing, Education and Outreach, Pilots, Rule 32 funding, which is contingent upon a filing, and the Demand Response Potential Study.

SDG&E 2018-2022 Authorized Demand Response Budget							
PLS Eliminated	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Category 2 Total	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
Category 3 – Demand Response Auction Mechanism (DRAM) and Direct Participation Electric Rule 24/32							
DRAM, Including IT	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	\$ 0
SDG&E Electric Rule 32, Including IT, CONTINGENT UPON FILING	\$ 561	\$ 578	\$ 596	\$ 614	\$ 632	\$ 2,981	\$ 2,981
Category 3 Total	\$ 561	\$ 578	\$ 596	\$ 614	\$ 632	\$ 2,981	\$ 2,981
Category 4 – Emerging and Enabling Technology programs							
DR Emerging Technology	\$ 729	\$ 751	\$ 773	\$ 797	\$ 821	\$ 3,870	\$ 3,483
Technology Deployment	\$ 838	\$ 847	\$ 834	\$ 843	\$ 852	\$ 4,215	\$ 3,794
Technology Incentives	\$ 1,442	\$ 2,950	\$ 2,959	\$ 2,968	\$ 2,978	\$ 13,297	\$ 11,967
Category 4 Total	\$ 3,009	\$ 4,548	\$ 4,567	\$ 4,608	\$ 4,650	\$ 21,383	\$ 19,245
Category 5 – Pilots							
Armed Forces Pilot (AFP)	\$ 769	\$ 869	\$ 869	\$ 0	\$ 0	\$ 2,507	\$ 2,507
Over Generation Pilot	\$ 706	\$ 716	\$ 726	\$ 0	\$ 0	\$ 2,148	\$ 2,148
Constrained Local Capacity Planning Areas and Disadvantaged Communities Pilot	\$ 0	\$ 125	\$ 125	\$ 125	\$ 125	\$ 500	\$ 500
CBP Residential Pilot	\$ 708						\$ 708
Category 5 Total	\$ 2,183	\$ 1,710	\$ 1,800	\$ 125	\$ 125	\$ 5,235	\$ 5,943
Category 6 – Marketing, Education, and Outreach (ME&O)							

SDG&E 2018-2022 Authorized Demand Response Budget							
Local Marketing, Education and Outreach	\$ 853	\$ 882	\$ 902	\$ 922	\$ 944	\$ 4,502	\$ 4,502
Category 6 Total	\$ 853	\$ 882	\$ 902	\$ 922	\$ 944	\$ 4,502	\$ 4,502
Category 7 – Portfolio Support (includes EM&V, Systems Support, and Notifications)							
Regulatory Policy & Program Support	\$ 856	\$ 882	\$ 909	\$ 937	\$ 966	\$ 4,550	\$ 4,095
IT Infrastructure & Systems Support	\$ 2,083	\$ 1,914	\$ 1,583	\$ 1,808	\$ 1,443	\$ 8,831	\$ 7,948
Evaluation, Measurement & Verification (EM&V)	\$ 1,204	\$ 1,495	\$ 1,225	\$ 1,267	\$ 1,248	\$ 6,439	\$ 5,795
DR Potential Study	\$ 200	\$ 200	\$ 200	\$ 200	\$ 200	\$ 1000	\$ 1000
Category 7 Total	\$ 4,343	\$ 4,491	\$ 3,917	\$ 4,211	\$ 3,857	\$ 20,819	\$ 18,837
Total Authorized in 2018- 2022 Portfolio for SDG&E	\$ 16,597	\$ 17,725	\$ 17,329	\$ 15,882	\$ 15,767	\$ 82,592	\$ 78,618

(END OF ATTACHMENT 3)