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Decision 16-09-056 September 29, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION ADOPTING GUIDANCE FOR FUTURE DEMAND RESPONSE PORTFOLIOS AND MODIFYING DECISION 14-12-024

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Summary

This decision resolves remaining Phase Two and Phase Three issues of Rulemaking 13-09-011. As described below, the resolution of these issues provides guidance to Pacific Gas and Electric Company, San Diego Gas and Electric Company and Southern California Edison Company (jointly, the Utilities) for demand response budget and activities applications for existing models of programs beginning in 2018.

First, the decision determines that the Commission should modify Decision 14-12-024 by rescinding the requirement to collect data on fossil-fueled back-up generation in demand response programs and move forward with a prohibition of certain resources in demand response programs. We establish a date of January 1, 2018 to begin the prohibition of the use of certain resources to reduce load during demand response events. We also establish an enforcement program, as set forth in the ordering paragraphs.

Second, this decision provides guidance to the Utilities regarding existing models of demand response programs for 2018 and beyond portfolios. A future decision will provide guidance to the stakeholders regarding policies for new models of fast response programs including efforts to meet California's future flexible capacity and ancillary service needs. Hence, the Utilities will be required to file an application by January 16, 2017requesting approval of activities and funding for existing models of demand response programs.

Third, this decision adopts the following goal for demand response programs: *Commission regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and*

enable customers to meet their energy needs at a reduced cost. In support of the goal, we also establish a set of principles to guide future demand response policies and programs.

Fourth, this decision establishes a five-year budget cycle with a mid-cycle review, as described herein. Hence, the January 16, 2017 applications referenced above should request funding for years 2018 through 2022.

The second phase of Rulemaking 13-09-011 remains open to address the implementation of the cost causation principles adopted in Decision 14-12-024. Phase Three remains open to complete the demand response potential study and provide guidance to stakeholders on newer model programs to enable fast response demand response and help meet California's future capacity and ancillary service needs.

1. Background

On December 17, 2014, the Commission adopted Decision (D.) 14-12-024 approving a revised joint party proposal that set forth a path toward realization of many Phase Two and Phase Three issues in Rulemaking (R.) 13-09-011. Relevant to this Decision, D.14-12-024:

- Established three demand response working groups to develop proposals toward resolving the issues of Phase Three;
- Adopted a policy statement and a data collection requirement regarding the use of back-up generation in Commission-regulated demand response programs; and
- Approved the performance of a demand response potential study (Study).

Related to the working groups, Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), California Large Energy Consumers Association (CLECA), Johnson Controls, Inc., Comverge, Inc., Olivine, Inc., EnerNoc, Inc. (EnerNoc), and California Energy Storage Alliance (CESA), (jointly, the Petitioners) filed a Petition for Modification, on July 22, 2015, requesting the Commission to modify D.14-12-024 to authorize the continuation of the Integration Working Group and the Operations Working Group alleging that during the course of the two groups prior work, both Working Groups uncovered important implementation matters requiring further investigation by the groups. The California Independent System Operator (CAISO) filed a response on August 21, 2015 in opposition to the motion.

In regard to the use of back-up generation in Commission-regulated demand response programs, on September 29, 2015 the assigned Administrative Law Judge issued a ruling (September Ruling) describing an attached staff proposal that alleges difficulty with implementing the back-up generation data collection requirements of D.14-12-024 and recommends implementing a prohibition of certain resources in the demand response program and introduces a program to ensure these resources are not used to attain demand response incentives (Staff Proposal). Parties were invited to respond to the Staff Proposal and address specific questions for the record; parties filed opening comments on October 15, 2015 and reply comments on October 19, 2015. Subsequent to requests from several parties, a workshop was held in January 13, 2016 to discuss the Staff Proposal and alternatives. A draft workshop report was filed by the Utilities and parties were invited to correct any errors or omissions. The final workshop report, dated July 26, 2016 was accepted into the record via a July 27, 2016 ruling (January Workshop Report). On August 4, 2016, PG&E filed the only comments to the July 27, 2016 ruling stating that although the January Workshop Report's statements about the workshop discussion may be accurate, PG&E's

silence on specific points does not necessarily constitute agreement with the positions of the Energy Division or any other party. In response to a motion filed by the Joint Demand Response Parties, the Administrative Law Judge issued a Ruling amending the January Workshop Report to include the power point presentations made during the January Workshop.

The Study commenced in the spring of 2015. A technical advisory group, comprising representatives of PG&E, SDG&E, and SCE (jointly, the Utilities), demand response aggregators, regulatory agencies, advocacy organizations and others, was established to contribute technical expertise and inform the approach and methods of the Study.[1] On April 1, 2016, Lawrence Berkeley National Laboratory (Study Contractor) delivered its interim results to the parties of the proceeding.[2] The interim results use advanced metering infrastructure data and customer load shapes to show the potential for customer end uses to meet the system and local peak capacity needs that drive resource adequacy requirements.[3] A workshop to discuss the results and methodology was held on April 13, 2016. A May 20, 2016 ruling requested parties to respond to several

[1] Technical Advisory Group members includes representatives of the following agencies, companies, and organizations: CLECA, CAISO, California Energy Commission (CEC), Consumer Federation of California (CFC), Comverge, Demand Analysis Working Group, DNV-GL, EnerNOC, Environmental Defense Fund (EDF), Itron, Joint Demand Response Parties, Navigant, Newport Consulting, Office of Ratepayer Advocates (ORA), Olivine, OPower, PG&E, SDG&E, SCE, and The Utility Reform Network (TURN).

[2] The *Interim Report on Phase I Results of the 2015 California Demand Response Potential Study*, April 1, 2016, is available at: http://www.cpuc.ca.gov/General.aspx?id=10622.

[3] The second phase of the Study, due in Fall of 2016, broadens the scope to more advanced technology options that enable new types of demand response including fast demand response that can meet future capacity and ancillary services needs, and address oversupply.

questions regarding the Study. Parties filed responses and comments on July 1, 2016 and reply comments on July 15, 2016.

As to the resolution of the Phase Three scope of issues, two rulings were issued (March 4, 2016 and May 20, 2016) asking parties to comment on remaining questions for this proceeding. Parties filed comments and reply comments to each ruling.

2. Issues Before the Commission

This decision addresses remaining Phase Two and Phase Three issues and provides guidance to the Utilities regarding the contents of 2018 applications for existing models of demand response programs.

There are two outstanding Phase Two issues: 1) implementation of the cost causation principles, and 2) back-up generation and the Staff Proposal described in Section 1 of this decision. The record regarding the implementation of the cost causation principles is incomplete and, thus, the issue is not resolved in this decision. Pursuant to Public Utilities Code Section 1708, the Commission addresses the question of whether it should revise D.14-12-024, Ordering Paragraphs 12 through 15, in regard to the issues of the required collection of data on fossil-fueled back-up generation in demand response programs, whether the Commission should adopt a Staff Proposal to prohibit the use of certain types of resources in demand response programs, and whether the Commission should adopt the Staff Proposal for enforcement and validation mechanisms or an alternative. Specifically, this decision addresses whether the Commission should modify the following Ordering Paragraphs of D.14-12-024:

> 4. *We adopt the terms and conditions of Issue Areas 2 and 4 of the Settlement, as attached in Appendix 1 of this decision, with the following modifications: (f) We establish the following reporting requirements: i) Integration Working Group – Reports (filed as*

compliance reports) on the meetings held, the products developed, and the groups' successes and missteps; the mid-year report referred to in the charter, which is to include proposed changes, priorities and time-line, shall also be filed no later than June 30, 2015, as a compliance report; iii) Operations Working Group – Given the narrow scope of the working group and the necessity to vet and integrate the results, all finalized Valuation Working Group conclusions must be filed to the Commission in a compliance report by June 30, 2015.

11. It is reasonable to adopt as a policy statement that fossil-fuel emergency back-up generation resources should not be allowed as part of a demand response program for resource adequacy purposes, subject to rules adopted in future resource adequacy proceedings.

12. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall require any non-residential demand response contracted customer to self-certify the following: a. Whether the customer owns or operates a back-up generator; and b. If the customer owns such a generator, what is the make, model and location of the generator.

13. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file the back-up generation data, as a compliance document in this proceeding, no later than November 30, 2015.

14. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) shall collect information about hourly usage information for each of the back-up generators owned by non-residential customers that participate in their demand response programs. The Utilities are to map that information against their demand response events and the load reductions provided by the participants so that the Commission is able to determine the extent to which backup generation is used coincident with demand response events and how that usage compares against the load drop provided by the participant. This information shall be collected over the course of 2015 and shall be filed as compliance document in this proceeding no later than November 30, 2015.

15. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file a Tier One advice letter, within 60 days from the issuance of this decision,

> *revising its tariffs to implement the data collection required by Ordering Paragraphs 11, 12, 13 and 14.*

In regard to the third phase of this proceeding, this decision will address the remaining scope issues: 1) determining a goal for the demand response programs; 2) determining the role of the Utilities in both supply and load modifying demand response resources; and 3) determining the demand response program budget cycle.

In combination with addressing the issues listed above, this decision also provides guidance to the Utilities regarding the contents of their 2018 demand response applications for existing programs.

This decision determines whether to grant a Petition for Modification requesting the Commission to modify D.14-12-024 to authorize the continuation of the Integration Working Group and the Operations Working Group.

3. Coordination with Related Rulemakings

The Commission has undertaken general rulemakings that directly affect demand response programs, including: Distribution Resources Plans (R.14-08-013), Integrated Distributed Energy Resources (R.14-10-003), Residential Rate Reform (R.12-06-013) and Integrated Resource Planning (R.16-02-007). We discuss these proceedings below and their influence on future demand response programs.

The Distribution Resources Plans (R.14-08-013) and Integrated Distributed Energy Resources (R.14-10-003) will address two issues that parties have highlighted in this rulemaking: the integration of distributed energy resources and the valuation of distributed energy resources.

The Commission initiated the Distribution Resources Plan proceeding to establish policies, procedures and rules to guide regulated energy utilities in developing proposals that will move a utility toward a fuller integration of distributed energy resources with the utility's distribution grid planning, operations, and investment. Together with R.14-10-003, the two proceedings will create an end-to-end framework from the customer side to the utility side of the grid to implement the utilities' proposals for Public Utilities Code Sections 769(b)(2) and (b)(3),[4, 5] including the identification of tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources and cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

D.15-09-022 acknowledged an overlap between the two proceedings, but also clarified the demarcation between the two. The decision stated that in R.14-08-013 the Commission will delineate the distribution system needs and how those needs can be optimally provided by distributed energy resources. Through the development of a Locational Net Benefits Analysis, currently underway, the Commission will determine the value of the distributed energy resource attributes required to fill the distribution system needs. This will

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[4] Public Utilities Code Section 769(b) provides:

Not later than July 1, 2015, each electrical corporation shall submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources. Each proposal shall do all of the following:

(2) Propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.

(3) Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

[5] All further references to sections are to Public Utilities Code unless otherwise specified.

address the concerns expressed by parties in this proceeding that the Commission is not appropriately valuing demand response.[6]

The purpose of R.14-10-003 is to develop a framework to enable a wide portfolio of distributed energy resources and determine how the resources could be procured. Specifically, the intention of R.14-10-003 is to consider how to best enable the utilities, other administrators, and electric market actors to offer a wide portfolio of demand-modifying technologies best tailored to the explicit characteristics of individual customers.[7] R.14-10-003 will also determine how to implement the tariffs, contracts, and other mechanisms developed in R.14-08-013.

D.15-09-022 recognized that Public Utilities Code Section 769 requires that distribution grid planning be informed by distributed energy resources, including the choices made by customers. However, the Commission also acknowledged that customer choice should be informed by the impact of those choices on the grid's needs.[8] Thus, the Commission broadened the scope of R.14-10-003 beyond looking at what the utilities offer customers (integrated demand side management) and committed to focusing on what customers could offer the utility (the integration of distributed energy resources).[9]

Furthermore, the Commission found a need for the harmonization between grid and customer benefits in the integration of distributed energy resources. In comments to the May 20, 2016 Ruling in this proceeding, SDG&E

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[6] *See*, for example, Advanced Microgrid Solutions (AMS) July 1, 2016 Comments at 3, EDF July 1, 2016 at 7, and PG&E July 1, 2016 Comments at 7.

[7] D.15-09-022 at 3.

[8] *Id*. at 14.

[9] *Ibid.*

stated that given the costs of demand response, maximization may require fewer customers with greater loads and greater flexibility.[10] Currently, R.14-10-003 continues to consider whether policies supporting the integration of distributed energy resources should maximize grid benefits or customer participation and whether customer incentives should be uniform or differentiated by locational value. Results of those considerations will have a direct effect on future demand response programs.

The May 20, 2016 Ruling in this proceeding highlighted a recommendation from the Interim Report of the Demand Response Potential Study that the integration of demand response services with other services could lead to reduced costs, increased potential and decreased customer confusion. In comments, SDG&E observed that a holistic approach is needed and referenced the work being done in R.14-10-003.[11] We agree that the competitive solicitation framework proposed in R.14-10-003 should be the methodology for the proposed integration, as it directly improves demand response programs by incentivizing the integration of different resources. On August 1, 2016, the Competitive Solicitation Framework Working Group in R.14-10-003 filed a report recommending details of seven aspects of the framework: 1) services to be bought and sold; 2) methodologies to count services provided and ensure no duplication; 3) solicitation rules or principles; 4) solicitation oversight needs; 5) solicitation evaluation methodology; 6) solicitation pro forma contracts; and 7) outreach plans. It is anticipated that the proposal for the framework brought

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[10] SDG&E July 1, 2016 Comments at 33.

[11] SDG&E July 1, 2016 Comments at 33.

forth by the Competitive Solicitation Framework Working Group will be considered by the Commission in the near future.

Two rate reform proceedings, R.12-06-013 (residential rates only), and R.15-12-012, will work together to address issues related to time of use rates. Time of use rates and Critical Peak Pricing were reviewed in the Study as load modifying resources. Several parties call for the Commission to send appropriate pricing signals to customers through time of use rate design, as well as other dynamic pricing programs.[12] Likewise, Joint Demand Response Parties encourage the Commission to ensure that our efforts focus on educating customers on these pricing programs.[13] Opposing mandatory controls on customer usage, CLECA cautions that setting a goal for time of use rates may be difficult since customers will respond to rates as they do; there is no way to make them respond but education efforts may have an effect.[14] CLECA proposes that the Commission learn from the current pilots being conducted in the Residential Rate Reform proceeding; PG&E adds that the pilots will evaluate the effect of technology and tools on behavior change.[15] R.12-06-013 includes an effort to address education and outreach to potential time of use customers. Both PG&E and SCE recommend that the Commission address time of use rates outside of this proceeding.[16] We conclude that it is efficient for all time of use issues to be resolved in a focused manner in R.12-06-013 and R.15-12-012.

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[12] CLECA July 1, 2016 Comments at 3.

[13] CLECA July 1, 2016 Comments at 5 and 12-13.

[14] *Ibid.*

[15] CLECA July 1, 2016 Comments at 13 and PG&E July 1, 2016 Comments at 25-26.

[16] PG&E July 1, 2016 Comments at 25 and SCE July 1, 2016 Comments at 13.

Lastly we discuss R.16-02-007, the Integrated Resource Planning proceeding. R.16-02-007 is the Commission's primary venue for the implementation of the Senate Bill (SB) 350 requirements related to integrated resource planning. The legislative requirements in SB 350 represent an evolution that builds on the Commission's previous long term procurement planning work and evolves and refines the implementation of the decade-long procurement loading order policy.

SB 350 mandates that the Commission adopt a process by 2017 for all jurisdictional load serving entities to submit integrated resource plans to ensure that the load serving entity's planning and procurement efforts are on track to meet the electricity sector's greenhouse gas emissions reductions targets to be established by the California Air Resources Board. SB 350 also requires the Commission to identify a diverse and balanced portfolio of resources needed to ensure reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner. The portfolio shall rely upon zero carbon-emitting resources to the maximum extent reasonable and be designed to achieve any statewide greenhouse gas emissions limit pursuant to the California Global Warming Solutions Act of 2006 or any successor legislation. Additionally, the Commission is required to direct each electrical corporation to include a strategy for procuring best-fit and least-cost resources to satisfy the portfolio needs identified.

Guidance provided in this decision may require additional refinement by the Commission depending upon future decisions in R.16-02-007, R.15-12-012, R. 14-10-003, R. 14-08-013, and R.12-06-013.

4. Discussion

Two Phase Two issues remain to be resolved: 1) implementation of the cost causation principles, and 2) consideration of the Staff Proposal on the prohibition of the use of certain resources to reduce load during a demand response event (i.e., back up generation). At this time, there is insufficient information in the record of this proceeding to determine how to implement the cost causation principles adopted in D.14-12-024. Hence, the second phase of this proceeding remains open. We address the Staff Proposal below.

4.1. The Use of Back-Up Generation To Reduce Load During Demand Response Events

The following sections address whether the Commission should modify Ordering Paragraphs 11 through 15 of D.14-12-024 to reverse its prior decision not to implement a prohibition on allowing the use of certain resources in demand response programs.

We first determine that the proper notice and comment methodology has been used to address this issue and that parties have been provided adequate notice and opportunity to be heard through the following opportunities: a) comment on the Staff Proposal; b) participation in a workshop discussing the Staff Proposal and alternatives; and c) comment on this decision. We then determine that it is reasonable for the Commission to modify D.14-12-024 and, beginning January 1, 2018, implement a prohibition on the use of certain resources to reduce load during a demand response event. As a result of the comments and the discussion during the January 13, 2016 workshop, we adopt a modified version of the Staff Proposal as described below.

4.1.1. Procedural Issue

We first address the concern expressed by several parties that the Commission has not properly followed the law in addressing the staff proposal on fossil-fueled back up generation.[17] Section 1708 provides the Commission with the authority to revise any prior decision, with notice to the parties and an opportunity to be heard.[18] The Commission finds that both of these requirements have been fulfilled. Furthermore, as described below, we clarify that there is no requirement for the Commission to "petition" itself to modify a prior decision. Rather, the Rules of Practice and Procedure, Rule 16.4, is directed at *parties* desiring to petition the Commission for a decision modification.

The Joint Demand Response Parties contend that the staff proposal is legally flawed and that it and the September 29, 2015 Ruling are not the appropriate means by which to modify a Commission decision. Relying upon Section 1708, the Joint Demand Response Parties argue that Section 1708 in combination with Section 1705 requires that an opportunity to be heard entitles

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[17] *See* Joint Demand Response Parties Opening Comments at 1-16, CLECA Opening Comments at 1-11, California Clean DG Coalition at 2-3, Joint Demand Response Parties Reply Comments at 1-3, and SCE Reply Comments at 2.

[18] Section 1708 states that the Commission may at any time, upon notice to the parties and with opportunity to be heard, rescind, alter, or amend any order to decision made by it. In addition, Section 1708.5(a) states that the Commission shall permit interested persons to petition the commission to adopt, amend, or repeal a regulation. Relatedly, Section 1708.5(f) states that notwithstanding Section 1708, the Commission may conduct any proceeding to adopt, amend, or repeal a regulation using notice and comment rulemaking procedures, without an evidentiary hearing, except with respect to a regulation being amended or repealed that was adopted after an evidentiary hearing. The Commission has adopted rules to implement Section 1708.5. The Commission Rules of Practice and Procedure, Rule 16.4, describes the parameters by which *parties* (emphasis added) may seek a change in an issued decision.

parties to introduce evidence.[19] Additionally, the Joint Demand Response Parties assert that the staff proposal and September 29, 2015 Ruling should comply with Commission Rules of Practice and Procedure, Rule 16.4.

First, we underscore the fact that neither the Staff Proposal nor the September 29, 2015 Ruling make any decision about back-up generation or modifications to D.14-12-024. Rather, the Staff Proposal recommends a change in the back-up generation policy and proposes a process to implement the change. The purpose of the September Ruling, as stated in the ruling, was to provide parties the information contained in the Staff Proposal, thus incorporating the proposal into the record, and ask for comments on the proposal, which are also now incorporated into the record. This is a process the Commission has used in this proceeding as well as other proceedings.[20]

Second, the Joint Demand Response Parties misinterpret Section 1708 by not including Section 1708.5(f) in their analysis. Section 1708.5(f) states:

> Notwithstanding Section 1708, the Commission may conduct any proceeding to adopt, amend, or repeal a regulation using notice and comment rulemaking procedures, without an evidentiary hearing, except with respect to a regulation being amended or repealed that was adopted after an evidentiary hearing.

Earlier in this Rulemaking, parties waived evidentiary hearings on the issue of back-up generation.[21] Hence, the notice and comment procedure discussed in Section 1708 is the appropriate process to supplant evidentiary hearings.

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[19] Joint Demand Response Parties Opening Comments at 3-4.

[20] *See*, for example, the June 19, 2015 Ruling providing staff proposed changes to the demand response cost-effectiveness protocols and asking for party comments.

[21] *See* Motion for Adoption of Settlement Agreement, August 4, 2014 at 11. The Motion discusses the three issues that the settlement agreement does not address

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Third, the Joint Demand Response Parties' contention that the Commission must comply with Commission Rules of Practice and Procedures, Rule 16.4 is incorrect. Rule 16.4 is a set of rules for *parties* (emphasis added) to comply with when requesting a change to a decision. In fact, Rule 16.4 (a) begins by stating that, a "petition for modification asks the commission to make changes to an issued decision." In effect, the Joint Demand Response Parties contention would have the Commission petitioning itself to ask itself to change a decision. CLECA and the Joint Demand Response Parties argue that the Commission did this in R.11-03-012 where the assigned Administrative Law Judge issued a Ruling attaching a staff proposal asking for parties' comment regarding changes to a prior decision.[22] CLECA asserts that the Administrative Law Judge Ruling in R.11-03-012 gave parties the opportunity to offer comments and reply comments on the newly admitted record evidence. We find that the September Ruling in this proceeding mirrors the structure of the ruling in R.11-03-012 except for the use of the language, "modify D.14-12-024." In reviewing the language in the Staff Proposal, which was attached to the September Ruling, it is evident that the Staff Proposal requires a modification to D.14-12-024.[23] Again the purpose and

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or resolve; one of those being back up generation. In the bullet point on back up generation, the settlement states that "During public Workshop discussions on June 12, 2014, parties agreed that this issue did not require further evidentiary hearings but, instead, should be addressed in briefs." *See also* Settlement Agreement at 4: "…the treatment of fossil-fueled Back Up Generation (BUGs) associated with demand response resources used in conjunction with providing demand response services, have not been settled, and, instead, will be the subject of briefs to be filed…" *See also* ALJ Ruling Confirming Issues to Be Briefed, August 13, 2014.

[22] Joint Demand Response Parties at CLECA at 4.

[23] *See* September 29, 2015 Ruling, Appendix A at 3-4.

outcome of the September Ruling was to provide parties an opportunity to be heard and to provide the Commission with the opportunity to build a record to make a determination on whether to adopt the Staff Proposal, which would thus require modifying D.14-12-024.

For the prior three reasons, we find that the issuance of a Ruling, which incorporated the Staff Proposal, asked questions regarding the Staff Proposal, and allowed comment on the Staff Proposal, is a proper notice and comment methodology to create a record in this proceeding for this decision. Furthermore, parties were provided an additional opportunity to discuss the Staff Proposal during the January 13, 2016 workshop. Parties have been provided adequate notice and opportunity to be heard on the modification of D.14-12-024 to change the back-up generation provisions.

In the following section, we turn to the Staff Proposal and address the following issues:

1) Whether the Commission agrees with the Staff Proposal regarding the difficulty of collecting back-up generation data and, therefore, whether the Commission should modify D.14-12-024, Ordering Paragraphs 12 through 15 and associated conclusions, findings, and text;

2) Whether the Commission agrees with the Staff Proposal to adopt a policy prohibiting fossil-fueled back-up generation in demand response programs and, therefore, whether the Commission should modify D.14-12-024, Ordering Paragraphs 12 through 15 and associated conclusions, findings, and text;

3) Whether the Commission should adopt the Staff proposed definition of fossil-fueled back-up generation;

4) Whether the Commission should adopt the enforcement mechanism recommended in the Staff Proposal; and

5) Whether the Commission should adopt the verification requirements in the Staff Proposal.

4.1.2. Whether to Modify D.14-12-024 in Regard to Back-Up Generation

As discussed below, we modify D.14-12-024 Ordering Paragraphs 12 through 15 and reverse our prior decision to defer the prohibition of the use of certain resources to reduce load during demand response events until further data could be collected. The continued delay of the data collection combined with a conflict with the Commission's clean energy policies requires us to implement a prohibition of the use of certain resources in demand response programs. We set a date of January 1, 2018 to begin the prohibition.

D.14-12-024 confirmed that fossil-fueled back-up generation is antithetical to the efforts of the Commission's Energy Action Plan and the Loading Order.[24] The Commission found, however, that a lack of evidence regarding the proliferation of back-up generation in demand response impeded the Commission from determining whether it is prudent to adopt a prohibition. At that time, the Commission was concerned that if it prohibited fossil-fueled back-up generation and the number of customers using these units was great, it could negatively impact the amount of megawatts curtailed during a demand response event. The Commission, therefore, directed the Utilities to collect data to determine the size of the issue and the way customers use back-up generation.

New information from Energy Division staff has revealed difficulty in collecting the data required by D.14-12-024. Furthermore, as discussed in detail below, the record shows that current Commission and California policies, along with questions regarding the accuracy of the data and the potential costs to collect the data, all combine to negate the benefit of collecting the data.

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[24] D.14-12-024 at Ordering Paragraph 10.

We begin with a discussion of Commission clean energy policies. Considered by the Commission to be policies of the highest importance, the Energy Action Plan and the Loading Order indicate a preference for cleaner technologies. More recently, Public Utilities Code Section 380.5 requires the Commission "to establish rules consistent with state and federal law for how and when back-up generation may be used within the demand response program"[25] The statute makes clear that efforts to incorporate demand response into the state's resource adequacy program should also reduce greenhouse gas emissions.[26]

During the January 13, 2016 workshop, Energy Division staff reiterated the Commission's clean energy policies where demand response is first in the Commission's Loading Order and is a preferred resource for procurement by the Utilities under Assembly Bill (AB) 57.[27] Energy Division underscored that the

[25] Furthermore, the statute also requires the Commission to establish reporting and data collection requirements to verify compliance with those rules as well as metering and monitoring policies.

[26] *See* D.14-12-024 at 58 quoting the enacting legislation, SB 1414 at Section 1(b). ("(b) In enacting this act, it is the intent of the Legislature to ensure that California and the Public Utilities Commission help meet the state's greenhouse gas emissions reduction goals and achieve electrical grid reliability by increasing the utilization of demand response.") http://www.leginfo.ca.gov/pub/13-14/bill/sen/sb_1401-1450/sb_1414_bill_20140926_chaptered.html.

[27] January Workshop Report at 3. "[Energy Division] has taken a layered approach to propose which resources should be prohibited, using a number of criteria. Initially, there was a set of three environmental criteria. [Energy Division] states the first is the State's Energy Action Plan Loading Order (and Public Utility Code Section 454.5) which puts energy efficiency and "demand reduction" as first in the loading order and as a preferred resource for [investor owned utilities'] procurement (under Assembly Bill (AB)57). [Energy Division defines [demand response] as a reduction in demand that is not supported by a fossil-fueled resource and contend that the California Public Utilities Commission's (Commission) policy decisions are clear in that regard. The second environmental criterion is greenhouse gas (GHG) reduction,

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Loading Order indicates that demand response is a reduction in demand that is not supported by fossil-fueled resources.[28] Energy Division also referenced SB 1414, which states that the intention of demand response is to reduce greenhouse gases.[29] No party provided any objection to these statutory directives.

The Commission's adopted policy statement regarding fossil-fueled back-up generation essentially has no effect without any associated conditions or requirements. We conclude that not having a clearly identified prohibition on the use of certain resources to reduce load during demand response events conflicts with our adopted policy statement and may prevent the Commission from meeting its aggressive clean energy policy goals.

We now turn to a discussion regarding the value of the data collection plan. In the Staff Proposal, Energy Division explained that, upon review of the Utilities' data collection plan regarding the use of back-up generation in demand response programs, Energy Division concluded that the proposed data collection plan is flawed.[30] The Staff Proposal pointed to four main "flaws": 1) The meter data requested by the Utilities is "likely to be in the form of cumulative run hours" and this data does not necessarily indicate whether a back-up generator was used during a demand response event;[31] 2) Operating data may only be

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where again SB 1414 states that [demand response] is intended to reduce GHGs. Third, on public health, SB 1414 discusses "other pollutants" and local area pollutants."

28 *Ibid.*

29 *Ibid.*

30 Staff Proposal at 2.

31 *Ibid.*

available for back-up generators that are 50 horsepower or larger; 3) The data collection plan relies on the back-up generator owners voluntarily providing the required data; and 4) Cost estimates for the data collection are unknown. Because of these "flaws," Energy Division suspended the Advice Letters. Furthermore, Energy Division contends that D.14-12-024 requires modifications to address these flaws, but recommends, instead, that the Commission abandon the data collection and prohibit the use of back-up generation.

In the September Ruling, parties were asked to comment on whether the data collection plan should be modified or replaced with a prohibition on fossil-fueled back-up generation in demand response programs. PG&E and SCE argue that there are too many unknowns absent this data and thus, the Commission should allow the utilities to move forward with the data collection and require Energy Division to schedule workshops so that the parties can discuss the data collection plan's alleged flaws and develop improvements to address those flaws.[32] Furthermore, PG&E disagrees with the characterization of the plan as "flawed" and assert that the Energy Division should have provided additional guidance as requested by the Utilities.[33] SCE contends that the Commission should allow for a timely but reasonable process to collect data.[34] CLECA and the Joint Demand Response Parties also support continuing the data collection, contending that the Commission cannot make an informed policy decision without the data.[35]

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[32] SCE Opening Comments at 3 and PG&E Opening Comments at 2.

[33] PG&E Opening Comments at 2-3 citing Advice Letter 4582-E.

[34] SCE Opening Comments at 6.

[35] CLECA Opening Comments at 12 and Joint Demand Response Opening Comments at 17.

SDG&E and ORA support abandoning the data collection effort, calling it potentially costly and useless.[36] Both argue that expending resources waiting for the completion of this data collection would not necessarily provide useful or reliable information and would only postpone implementing a prohibition policy.[37] In particular, ORA highlights two barriers: operating data may not be able to demonstrate if the unit was operated coincident with a demand response event or the lack of operating data for units rated less than 50 horsepower.[38] Sierra Club maintains that the lax current regulations on back-up generation metering would also lead to inaccurate and incomplete data.[39] No party disputed these barriers. Furthermore, SDG&E concludes that adopting a prohibition policy now would be more expedient and pragmatic given the unreliability of the data that might have been collected with great effort and likely very little reward.[40] However, other entities suggest we should not be hasty with a decision to abandon data collection.[41]

We underscore that this is the second time that the Commission has requested the Utilities to collect data and this is the second time we have received more questions from the Utilities than data.[42] Given that the

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[36] SDG&E at 2 and ORA at 5.

[37] *Ibid.*

[38] ORA Opening Comments at 3.

[39] Sierra Club Opening Comments at 2.

[40] SDG&E at 2.

[41] Bloom Energy at 3. *See also* SCE Opening Comments at 6, requesting a timely but reasonable process.

[42] D.11-10-003 required the Utilities to collect data on the use of back-up generation; a directive that was ignored. *See D.14-12-024 at 51 citing D.11-10-003 at Ordering Paragraph 34.*

Commission initially asked the Utilities to collect this data in 2011, a decision in 2016 – five years later – to abandon the data collection is anything but hasty. While Joint Demand Response Parties argue that there are multiple advantages to the collection of this data, we reiterate that determining the size of the problem was the sole reason for our delaying the initial implementation of a prohibition.[43]

PG&E suggests that we wait to allow the demand response potential study to be complete and "see what data can be gleaned from it to help inform this issue."[44] However, the purpose of the data collection was to determine the number of customers using back-up generation; whereas the purpose of the demand response potential study is to "assist the Commission in setting a goal (for demand response) based on potential, needs, and value."[45] The two do not intersect; thus we dismiss the claim by PG&E that the demand response potential study will help inform the back-up generation issue.[46]

Lastly, there are questions regarding the cost to collect this data. According to the Staff Proposal, the Utilities provided no cost estimates for the data collection efforts. The Staff Proposal claims that the Utilities have implied that costs would be in the millions of dollars due to a reliance on consultants and

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43 Joint Demand Response Parties Opening Comments at 18; D.14-12-024 at 50 ("[W]e find that we should first ascertain the depth of this issue by determining the number of back-up generators being used and the extent to which they are being used.")

44 PG&E at 3.

45 D.14-12-024 at 18.

46 Subsequent to the filing of the comments by PG&E, the results of the Study regarding existing demand response programs have been completed and do not include data on the use of back-up generation.

surveys to extract data. No party provided any debate to the contrary. Hence, questions remain regarding the costs of data collection.

For all of the aforementioned reasons, we find it reasonable to abandon the data collection for fossil-fueled back-up generation and to move forward with a prohibition on the use of certain resources for the purposes of load reduction during a demand response event, which we detail further below. The purpose of the data collection required by D.14-12-024 was to ascertain whether the implementation of a prohibition on back-up generation would negatively impact the amount of demand response the programs would continue to curtail. Given the barriers described above, the data collection may not provide an adequate answer to our question. Furthermore, we have been waiting for this data since 2011 and have been unsuccessful for five years. Given the time and energy already expended waiting for data that could be inadequate both in terms of amount and usefulness, it is reasonable for the Commission to modify D.14-12-024 to abandon the data collection effort and to establish a date to begin the prohibition of the use of certain resources to reduce load during demand response program events.

We set a date of January 1, 2018 to begin the prohibition of the use of certain resources to reduce load during demand response events. This deadline provides the Utilities and other demand response providers with ample time to make necessary changes to tariffs and contracts in order to be in compliance with the prohibition and the implementation plan. In comments to the proposed decision, SCE and PG&E request fund shifting in the 2017 demand response budgets to fund the costs of the changes necessary to implement the prohibition.[47] This request is reasonable and we grant it as described below. Furthermore, as a result of the discussion during the January 13, 2016 workshop, we find aspects of the Staff Proposal require modification; we address these modifications below.

4.1.3. Staff Proposal Regarding Back-Up Generation

While we adopt modifications to D.14-12-024 to abandon the data collection and implement a prohibition on the use of certain resources to reduce load during demand response events, we also find that the Staff Proposal requires modifications.

First, we adopt the following list of prohibited resources for use during a demand response event: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in Combined Heat and Power (CHP)[48] or non-CHP configuration. Furthermore, we clarify that the following resources are exempt from the prohibition: pressure reduction turbines, waste-heat-to-power to be used for load reduction, storage coupled with renewable generation and stand-alone storage; the stand-alone storage resources

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[47] PG&E Opening Comments to the Proposed Decision, September 19, 2016, at 5-6; and SCE Opening Comments to the Proposed Decision, September 19, 2016, at 4-5.

[48] D.15-06-028 describes CHP, also known as cogeneration, stating that "production of these two products can be more fuel efficient than separate conventional electric generation and heat production." The decision noted that "as a result, fewer greenhouse gas emissions can result from a CHP facility, depending on the comparisons made." *See D.15-06-028 at 2. See also* Public Utilities Code §216.6 which defines cogeneration as the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse subject to a) at least 5 percent of the facility's total annual energy output shall be in the form of useful thermal energy, and b) where useful thermal energy follows power production, the useful annual power output plus one-half the useful thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

must meet the relevant greenhouse gas emissions standards adopted for the Self Generation Incentive Program (SGIP). We also grant exemptions from this enforcement for certain demand response programs, as further described below.

Second, enforcement of the prohibited resources shall be accomplished via revised program tariff language. Specifically, we require tariff language changes for residential customer programs describing the prohibition as well as notification and outreach about the changes for existing customers. For non-residential customer programs, we require two choices to be included in revised tariff language: signing an attestation to never use prohibited resources during a demand response event or accepting a default adjustment.

Third, as described further below, we required the Utilities to hire expert consultants to assess how to evaluate compliance with the enforcement program.

The Staff Proposal made several recommendations for how its proposed prohibition may be implemented. Those recommendations, in general, were:

a. PROHIBITION DEFINITION: As set forth in the Staff Proposal, the following fossil-fueled distributed energy resources should be prohibited or disqualified for use during demand response events: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in Combined Heat and Power (CHP) or non-CHP configuration. Furthermore, the Staff Proposal recommends that stand-alone storage and storage coupled with renewable generation should be allowed to be used during demand response events but must meet the relevant greenhouse gas emissions factor thresholds adopted for the Self Generation Incentive Program.[49]

b. ENFORCEMENT MECHANISM: The Commission should adopt a hybrid enforcement mechanism, differentiating between

49 D.15-11-027 Appendix B.

residential and non-residential customer sites and providing a range of certainty that is lower for residential customer sites and higher for non-residential sites.

c. VERIFICATION MECHANISM: If a demand response customer claims that it has no back-up generation on its premises, the Commission should require a utility or demand response provider to verify this claim bi-annually with site visits or by cross-examination of other data sets.

In the September Ruling, parties were invited to comment on the Staff Proposal and to respond to specific questions regarding the proposal. In the following section, we address the comments on the Staff Proposal in terms of the three recommendations; we also address the discussion that took place during the January Workshop.

4.1.3.1. Defining the Prohibition of Resources Used To Reduce Load During Demand Response Events

In regards to defining the resources that will be prohibited for use during demand response events, we adopt the list of resources prohibited to be used by a customer during a demand response event in return for an incentive to include the following: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in CHP[50] or non-CHP

[50] D.15-06-028 describes CHP, also known as cogeneration, stating that "production of these two products can be more fuel efficient than separate conventional electric generation and heat production." The decision noted that "as a result, fewer greenhouse gas emissions can result from a CHP facility, depending on the comparisons made." *See* D.15-06-028 at 2. *See also* Public Utilities Code Section 216.6 which defines cogeneration as the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse subject to a) at least 5 percent of the facility's total annual energy output shall be in the form of useful thermal energy, and b) where useful thermal energy follows power production, the useful annual power output plus one-half the useful thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

configuration. Furthermore, we approve storage coupled with renewable generation and stand-alone storage to be used during demand response events, but the stand-alone resources must meet the relevant greenhouse gas emissions standards adopted for the SGIP. As further described below, this decision also modifies the proposed list of prohibited resources to allow pressure reduction turbines and waste-heat-to-power to be used for load reduction during demand response events.

In comments to the September Ruling, SDG&E and PG&E expressed a concern that the list of prohibited fossil-fueled distributed energy resources is overly broad and not limited to back-up generation.[51] CLECA agreed that the definition is broad and called for a clear, rational definition consistent with federal and state law, as required by Section 380.5.[52] CLECA also suggested working with state and local air quality agencies on the development of a definition.[53]

During the January Workshop, the Commission's Energy Division staff conceded that there may be confusion due to the conceivably inappropriate use of the term back-up generation over the course of the proceeding. Energy Division staff explained that backup generation is a specific use of distributed generation and has been used over time as "short-hand" for any resources the Commission ultimately deems should be prohibited. Energy Division noted that fossil-fueled resources can be used in either non back-up or emergency configurations. Because of the Commission's clean energy policies previously

[51] SDG&E Opening Comments at 2 and PG&E Opening Comments at 4.

[52] CLECA Opening Comments at 12 and 14.

[53] CLECA Opening Comments at 15. See also Bloom Opening Comments at 4.

discussed, Energy Division clarified that in the Staff Proposal the prohibition of the specified resources has been expanded from solely "back-up generation resources" to "the use of specific resources for the purposes of load reduction during demand response events in return for an incentive." Energy Division stated that this is to ensure that demand response is actual load reduction and not substituted with fossil-fueled generation, as required by Commission clean energy policies. Hence, Energy Division clarified that the proposed prohibited resources should include distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas in CHP or non-CHP configuration.[54, 55]

In response to Energy Divisions explanations, several parties made inquiries regarding the resource prohibition clarification. Parties also suggested additional exclusions to the prohibition. We address these below.

Parties asked why all fossil-fueled resources, including those participating in the SGIP, are proposed to be prohibited. Energy Division reiterated that the list of prohibited resources results from its understanding that demand response is an actual reduction in demand, not supported by a fossil-fueled resource. Parties targeted the issue of bottoming cycle CHP[56] versus topping cycle CHP,

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[54] January Workshop Report at 3.

[55] Energy Division clarified that in the Staff Proposal owning a prohibited resource would not render a customer ineligible to participate in a demand response program.

[56] Bottoming Cycle CHP, also known as waste heat to power, uses residual heat from process that generates heat. The Commission's SGIP considers waste to heat power to be a renewable resource and not subject to greenhouse gas standards. *See* D.09-06-051 which established that the attribution of greenhouse gas emissions associated with the electricity from a bottoming-cycle facility is limited to just the supplemental firing used since no new fuel is used during the production process. *See also* D.15-06-028 which explains that "since bottoming-cycle CHP uses "waste heat" as its primary input to generate electricity, a bottoming-cycle CHP facility

Footnote continued on next page

noting that the two processes are different in that in the topping cycle process, a facility produces electricity first and then captures the waste heat from that generation and uses it in a thermal application; whereas in a bottoming-cycle CHP facility, the heat is produced first by or as part of an industrial process, and then lower-grade waste heat from that industrial process is captured and used to generate electricity.[57] Johnson Controls, Inc. noted that CHP facilities run for many reasons including as part of regular plant operations while load reduction for demand response events may be provided from a different part of the facility. In response, Energy Division stated that in the case of CHP, the customer's load reduction (independent of the prohibited resource generation) will indicate the customer's demand response performance and compensation.

Previously in this decision, we described the Commission's clean energy policies and have determined that the lack of a prohibition of the use of fossil-fueled resources conflicts with those policies. Hence, we conclude that CHP facilities should be included in the list of prohibited resources used to reduce load during demand response events. However, we agree that bottoming cycle CHP, otherwise known as waste to heat power should be excluded from the list of prohibited resources because in the SGIP proceeding, the Commission has deemed this to be a renewable resource. Furthermore, the SGIP proceeding has also determined that pressure reduction turbines are also considered renewable. Therefore, we exclude these resources from the list of prohibited resources.

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operator will often combust a small amount of natural gas to stabilize the heat to a consistent level suitable for electricity production. This process is known as supplemental firing.

[57] D.15-06-028 at 3.

Parties queried why storage is proposed to be excluded from the prohibition. Because energy storage is considered to be a strategic resource to meet AB 2514 requirements,[58] Energy Division proposes to exclude storage coupled with renewable generation and stand-alone storage but require the stand-alone to meet the relevant greenhouse gas emissions factor thresholds established in the SGIP program.[59] The intent of AB 2514 confirms that the Commission is required to expand the use of energy storage systems to minimize greenhouse gas emissions.[60] It is reasonable to ensure that the adopted list of prohibited resources do not conflict with statutory requirements of AB 2514. Hence, we exclude energy storage from the list of prohibited resources.

4.1.3.2. Enforcement of the Prohibition

As a result of the party comments and the discussion during the January Workshop, we revise the Staff Proposal and adopt an enforcement program whereby the Utilities would provide tariff language changes, describing the

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58 AB 2514 was approved by the Governor on September 29, 2010.

59 January Workshop Report at 4.

60 Section 1 of AB 2514 states that the legislature finds that (a) Expanding the use of energy storage systems can assist in integrating increased amounts of renewable energy resources into the electrical transmission and distribution grid in a manner that minimizes emissions of greenhouse gases.

(b) Additional energy storage systems can optimize the use of wind and solar energy.

(c) Expanded use of energy storage systems can reduce costs to ratepayers.

(d) Expanded use of energy storage systems will reduce the use of electricity generated from fossil fuels to meet peak load requirements and can avoid or reduce the use of electricity generated by high carbon-emitting electrical generating facilities.

(e) Use of energy storage systems to provide the ancillary services otherwise provided by fossil-fueled generating facilities will reduce emissions of carbon dioxide and criteria pollutants.

prohibition, for all relevant residential demand response customer programs, including the current demand response auction mechanism pilots and any future demand response auction mechanism. We clarify that the enforcement would begin on January 1, 2018. We also require all demand response providers (the Utilities and third party providers) to furnish to existing customers notification and outreach about the changes. In comments to the proposed decision, PG&E requested clarification on whether the responsibility of notification and outreach should fall on the Utilities or, in the case of aggregator programs, third-party providers.[61] Because aggregators are the direct contact for customers in aggregator programs, it is the responsibility of the third-party aggregator to provide such notification and outreach. For non-residential customers, we adopt a choice of either signing an attestation to never use prohibited resources to reduce load during a demand response event or accept a default adjustment; both of these choices would be included in revised tariff language. We find these changes balance fairness, as required by the Public Utilities Code Section 453, with assurances to the Commission that clean energy policies are being met. As detailed below, the Utilities shall file advice letters to propose the prohibition tariff language for the affected programs. The prohibition of the use of the defined resources shall begin on January 1, 2018.

In order to enforce the prohibition of the use of certain resources for load reduction during demand response events, the Staff Proposal recommended a "hybrid mechanism" where residential and non-residential customers have different enforcement mechanisms. The Staff Proposal laid out a process

[61] PG&E Opening Comments to the Proposed Decision, September 19, 2016 at 6.

whereby residential customers sign an attestation indicating a) whether they possess a proposed prohibited resource and b) if they own a prohibited resource they commit to not using the resource to reduce load during a demand response event. For non-residential customers, the Staff Proposal recommended two proration options: a default adjustment or a metered adjustment.

In regards to residential customers, SCE presented a revised proposal at the January Workshop, which would instead amend all residential demand response tariffs, with the exception of air conditioning (AC) cycling programs, to include an explanation of the prohibition.[62] Similarly, PG&E and SDG&E stated that if a prohibition is adopted by the Commission, it should be included as another provision in the tariffs; PG&E and SDG&E also proposed the exemption of AC cycling. Energy Division expressed a concern that updating the tariff could bury a prohibition in fine print, whereas an attestation is more transparent. Johnson Controls suggested that including the language in contracts is another method of enforcement. EnerNoc and SCE highlighted the burden of a multi-step process for customers: enrollment followed by attestation could discourage participation in demand response.[63] SCE agreed that the multi-step process is redundant.

In regards to non-residential customers, Sierra and ORA stated in their comments that they support the enforcement mechanism, highlighting that the proposal provides options to industrial and commercial customers.[64] NRDC agrees, noting that the hybrid mechanism provides balance between customer

62 January Workshop Report at 10.

63 January Workshop Report at 8.

64 Sierra Club Opening Comments at 5 and ORA at 7.

costs and environmental goals. However, the Joint Demand Response Parties contend that the hybrid approach is unfair because of its inconsistent treatment between customer classes.[65] CLECA agreed that the hybrid approach is discriminatory to large customers and calls upon the Commission to treat all classes of customers equally.[66]

During the January Workshop, Energy Division explained that because non-residential customers provide the bulk of demand response, it could be presumed that this class of customers is more likely to have a prohibited resource. EnerNOC discussed the Joint Demand Response Parties' proposal which, like the Utilities' proposals, supports the use of tariff and contract modifications and for the process to occur during the contracting process for customer efficiency. EnerNOC explained that by including a prohibited resources provision in the contract, customers are subject to the terms of the contract and non-compliance is grounds for cancellation.[67] ORA questioned how non-use of a prohibited resource could be verified. Johnson Controls replied that use of a prohibited resource would most likely be seen in the customer's load curtailment during a demand response event.[68]

Parties discussed the pros and cons of the proposed metering adjustments versus a default adjustment for those customers choosing proration for use of the prohibited resource. Some argued that the default adjustment could provide an

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[65] Joint Demand Response parties Opening Comments at 22.

[66] CLECA at 17.

[67] January Workshop Report at 12.

[68] *Ibid.*

incentive for owners to operate a prohibited resource during an event.[69] However, CLECA noted that the default adjustment is practical for those customers required to have a small backup generator to operate during an outage for health and safety reasons.[70] SCE and Johnson Controls maintained that in the case of metered adjustment approach, if the cost of meters is too high customers may not participate in demand response programs. PG&E added that it would have to undergo changes to its billing infrastructure to manage the additional data, thus adding to the ratepayer cost of this prohibition.

We begin by addressing the enforcement mechanism for residential programs, including the demand response auction mechanism pilots and future auction mechanisms. We first find it reasonable to exempt the following programs from this requirement: AC cycling programs, permanent load shifting programs, schedule load reduction programs (SLRP), the optional binding mandatory curtailment (OBMC), time of use rates, critical peak pricing, real time pricing, and peak time rebates. As noted by PG&E, the economics of using a prohibited resource in AC cycling programs (both residential and non-residential) are not supported because a customer can opt out of a cycling event for no cost or penalty.[71] SCE maintains that if a customer had a prohibited resource providing back-up power, the AC cycling device would prevent the air conditioner from operating.[72] PG&E provides justification for exempting other programs. Because SLRP is capped at zero megawatts, PG&E contends it should

[69] *Id.* at 13.

[70] *Ibid.*

[71] PG&E Opening Comments to the Proposed Decision, September 19, 2016 at 3.

[72] SCE Opening Comments to the Proposed Decision, September 19, 2016 at 3.

be exempt. Similarly, because the OBMC customers do not receive financial incentives, that program should also be exempt. Additionally, PG&E argues that because of the configuration of the permanent load shifting (PLS) programs, there is no benefit for a PLS program customer to use a prohibited resource. We find these exemptions to be reasonable and, therefore, they should be adopted by the Commission. Lastly, PG&E highlighted that SB 1414 exempted these rates and tariffs from any such prohibition.[73] In accordance with SB 1414,[74] we exempt the following demand response load modifying resources from the adopted prohibition: time of use rates, critical peak pricing, real time pricing and peak time rebates. The exemption will begin on January 1, 2018. We clarify that the prohibition and the exemptions will apply to the demand response auction mechanism pilot beginning with the 2018 delivery.

We now address the specifics of the enforcement mechanism. We find the parties' concern that the multi-step process could discourage customer participation to be valid. Thus, we find it reasonable to revise the Staff Proposal and eliminate the requirement of a residential customer attestation. Demand response providers (both the Utilities and third party providers) shall be responsible for ensuring their customers comply with this prohibition either through tariff language or contact language. We, therefore, adopt a tariff or contract language revision requirement where an additional and separate provision is added near the beginning of the tariff or the customer contract, highlighting the prohibition.

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[73] PG&E Opening Comments on the Proposed Decision, September 19, 2016 at 2.

[74] SB 1414 was approved by the Governor on September 26, 2014.

The prohibition provision shall include language explaining the prohibition and that the customer must agree not to use a prohibited resource to reduce load during a demand response event. Furthermore, the new provision should also include language explaining that customer compliance may be subject to verification and list all of the potential consequences for non-compliance. Demand response providers shall also provide outreach to existing customers notifying them of the tariff or contract language changes. As is the case with the current demand response auction mechanism pilot, all third-party providers must be able to demonstrate to the Utilities how it is enforcing the prohibition, as well as provide necessary documentation.

We address the concern regarding a violation of Public Utilities Code Section 453. Section 453 requires the Commission to ensure that "No public utility shall establish *unreasonable* (emphasis added) differences in rates, charges, service, facilities, or in any other respect, between classes of service." We find it appropriate, and therefore reasonable, to require less strict requirements from a class of customers where the requirements are unlikely to be applicable, i.e., residential customers are unlikely to have an additional source to power their air conditioner. Hence, we conclude that the Staff Proposal, as revised, does not violate Public Utilities Code Section 453.

We now turn to the enforcement proposal for non-residential customers. Here again, we find it appropriate and less burdensome to require a separate prohibition provision in the demand response program tariffs and contract language rather than a two- step attestation process. Demand response providers shall revise the program tariff or contract language to state that non-residential customers are required to indicate, at the time of enrollment, whether they have a prohibited resource on their premises and agree not to use it to reduce load during a demand response event. The new provision should also include language explaining that customer compliance may be subject to verification and list all of the potential consequences for non-compliance. For those non-residential customers who are required to use a prohibited resource for non-demand response operational reasons, a default adjustment shall be implemented. By adopting the default adjustment, we eliminate the need to adopt costly metering requirements. As approved in D.16-06-008, electronic signatures, in addition to traditional signatures, shall be acceptable for disclosing this information.

In comments to the proposed decision, ORA and Sierra Club/EDF argue that the Commission should impose metering requirements as opposed to attestation, contending that attestation is insufficient. Sierra Club/EDF maintains that in light of the high payments participants receive, devices to meter the use of prohibited resources are not expensive.[75] In reply comments, PG&E responded that the inexpensive data loggers referred to by Sierra Club/EDF only track total usage and would not record whether a prohibited resource was used *during* a DR event.[76] PG&E added that appropriate submitters may be much more costly than the customer's demand response incentives, which could make participating in demand response unattractive for the customers.

The Utilities shall each file a tier three advice letter proposing draft language for the new prohibition tariff provision for review and approval by the

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[75] Sierra Club/EDF Opening Comments on Proposed Decision at 7.

[76] PG&E Reply Comments to Proposed Decision at 2.

Commission. The advice letters shall also include proposals to shift 2017 demand response funds to cover the implementation costs including customer outreach. The advice letters shall be filed no later than 90 days from the issuance of this decision. Third party demand response providers are required to include similar language in customer contracts, provide notice and outreach to current customers, and be able to demonstrate to the Utilities how it is enforcing the prohibition.

4.1.3.3. Verification Process

In order to verify that customers are in compliance with the prohibition described in the revised tariff language, we require the Utilities to jointly hire expert consultants to 1) assess how to evaluate whether customers are complying with the prohibition, and 2) provide recommendations on a verification plan. The Utilities shall serve the report to the service list no later than April 1, 2017. Subsequently, the Utilities shall host a workshop on the verification plan report, inviting all parties as well as representatives of the Commission's Energy Division. No later than July 1, 2017, the Utilities shall file an Advice Letter requesting approval of a final proposed verification plan, incorporating feedback received during the workshop.

The Staff Proposal recommended a verification process that encompassed either bi-annual site visits or a cross examination of data with air quality management districts or SGIP administrators. The responsibility for the site visits would fall on either third-party providers or the Utilities, depending upon the administration of the program.

CLECA, Joint Demand Response Parties, PG&E, SDG&E and SCE oppose the required site visits. During the Workshop, EnerNOC reiterated its opposition to site visits, stating that this would require additional staffing and costs to aggregators. SDG&E considers self-attestation to be sufficient for verification.[77] ORA and Sierra Club argue that annual site visits are needed because neither self-attestation nor verification through data are sufficient.[78] EnerNOC noted that the requirement of a site visit does not address whether the prohibited resources is being used to reduce load during a demand response event.[79] Energy Division staff agreed stating that the best way to know whether prohibited resources is being used is to meter the resource simultaneously with a demand response event.[80]

Several parties offered alternatives to the site visits. CLECA recommended that there could be a "potential for spot checks" based on local air quality indicators.[81] Similarly, PG&E suggested that a small number of sample sites should be inspected to determine how well the attestation system is working and then a number of site visits could be increased if there appears to be inaccurate attestations.[82] SCE proposed a third-party certification of a selective audit, such that with every year, a larger portion of the population is audited. SCE, as well as Nest Labs, Inc. (Nest), recommend that the AC Cycling programs be exempt from the audit.[83]

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77 SDG&E October 15, 2015 Comments at 5.

78 ORA October 15, 2015 Comments at 9, ORA October 19, 2015 Comments at 10 and Sierra Club October 15, 2015 Comments at 6.

79 January Workshop Report at 15.

80 *Ibid.*

81 CLECA October 15, 2015 Comments at 18.

82 PG&E October 15, 2015 Comments at 10.

83 January Workshop Report at 10.

We find that requiring bi-annual site visits for every residential and non-residential customer would be cost prohibitive. As we have determined that prohibition language shall be included in the tariff, with a requirement for non-residential customers to attest to not use the prohibited resource or take a default adjustment, we do not see the advantage of requiring bi-annual site visits for every customer. However, prudence requires some measure of verification. SCE presented the idea of a selective audit program, but provided no specifics. We find that a selective audit program should provide the balance of verification without the costliness of annual site visits during a demand response event.

Accordingly, we direct the Utilities to work together to immediately hire expert consultants to assess whether it is possible, and if so by what methods and data sources, to evaluate whether customers are complying with the prohibition policy. Further, the consultants shall make recommendations on how best to design an audit verification plan. All meetings with the consultants shall include a representative of the Commission's Energy Division. The Utilities are authorized to access existing measurement and evaluation funds approved in D.16-06-029 in order to fund the contract for the consultants.

The Utilities shall serve the consultant's report on its findings to the service list no later than April 1, 2017. Subsequently, the Utilities shall host a workshop on the audit verification plan report, inviting all parties as well as representatives of the Commission's Energy Division. No later than July 1, 2017, the Utilities shall file an Advice Letter requesting approval of a final proposed audit verification plan, incorporating feedback received during the workshop. The verification plan shall be effective January 1, 2018.

4.2. Phase Three Issues

4.2.1. Remaining Schedule

The results of the 2015 Demand Response Potential Study are being submitted in two phases: the first phase, delivered in April 1 2016, focused on meeting system and local peak capacity needs, i.e. existing programs, and the second phase, to be delivered in October 2016, will be focused on newer model demand response, especially targeting flexible resource adequacy, ancillary services and reverse demand response. We determine that to ensure continuation and improvement of existing demand response programs it is prudent for this decision to focus on the adoption of guidelines for the existing models of demand response programs so that the Utilities are able to file applications in a timely manner for 2018 programs. As described below, a second decision to be focused on new and advanced demand response programs will be developed following the issuance of the second phase of the 2015 Demand Response Potential Study. We anticipate that the newer model demand response programs will begin in 2020.

The March 4, 2016 Ruling informed parties the results of the Study would be delivered in two phases and explained the timing for the results. The Ruling provided three scenarios and asked parties to comment on the scenarios. The scenarios are: a) Delay Scenario incorporating both phases of the Study into one guidance document and postponing the filing of 2018 demand response applications until April 2017 thereby creating the need for another bridge funding decision; b) Supplemental Application Scenario where the Utilities would file an initial demand response application adhering to guidance based on the Phase One results followed by a supplemental application adhering to guidance based on the second phase results; and c) Two Decision Scenario where the Commission would provide two sets of guidance based on the two phases of the Study and the Utilities would file two separate applications: one for existing programs to begin in 2018 and one for new programs to begin in 2019.

Parties offered various advantages and disadvantages to each of the scenarios. Most parties expressed a preference for the Delay Scenario because it would only involve one application and one decision.[84] The Joint Demand Response Parties offered an alternative scenario of the Delay Scenario where the Commission would just continue the 2017 bridge funding through 2018. ORA objected to the Delay Scenario stating that it would not be prudent to adopt yet another year of bridge funding and continue to delay a broader review of the demand response portfolio.[85] CAISO similarly objected to the Delay Scenario; however its concern is predicated on the belief that a delay in bifurcation would indicate willingness by the Commission to defer the bifurcation date.[86]

While we agree that it could be more administratively efficient for the Commission to adopt a scenario that has one application and one decision, we consider our review of the two sets of programs to be two different situations. We have already moved forward with improvements to the existing set of demand response programs with the changes made for program year 2016 and more extensively for 2017. These improvements include the ability for most of the demand response programs' load reductions to be bid into the CAISO energy market, a major emphasis of this proceeding. Given our years of experience with

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[84] CLECA March 18, 2016 Comments at 3-4; PG&E March 18, 2016 Comments at 2; SDG&E March 18, 2016 Comments at 2; and SCE March 18, 2016 Comments at 2.

[85] ORA March 18, 2016 Comments at 3.

[86] CAISO March 18, 2016 Comments at 2.

the existing programs, a review of current models of programs should be routine. Hence, we should not delay their continuation with incremental improvements, which we discuss below. However, the same cannot be said regarding new advanced demand response programs.

It is unknown at this time what the second phase of the Study will present to us. Furthermore, it is unknown what the new advanced programs will entail, including who will provide these programs, the implementation timing and ratepayer effects. Because of this lack of experience and the unknowns, we anticipate many questions and concerns by all stakeholders regarding the new advanced programs. All of these unknowns may lead to a longer than normal review process. We, therefore, conclude that if a review of the existing models of programs is considered simultaneous to a review of new models of programs, there could be further delay in approving applications for existing models of programs. Hence, we find it reasonable to adopt the following timeline for future demand response applications:

- October 2016 – Commission provides Phase Two of Demand Response Potential Study
- January 16, 2017 – Utilities file applications for 2018 Demand Response Portfolios for existing models of programs and activities pursuant to Commission guidance
- Spring 2017 – Commission issues guidance decision for new models of demand response programs
- Fall 2017 – Commission issues Decision adopting 2018 portfolios for existing models of demand response programs and activities

4.2.2. Goal and Principles for Demand Response

We adopt the following goal for demand response programs that are regulated by the Commission:

Commission-regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost.

Furthermore, we establish the following set of principles for all demand response programs:

- *Demand response shall be flexible and reliable to support renewable integration and emission reductions;*
- *Demand response shall evolve to complement the continuous changing needs of the grid;*
- *Demand response customers shall have the right to provide demand response through a service provider of their choice and Utilities shall support their choice by eliminating barriers to data access;*
- *Demand response shall be implemented in coordination with rate design;*
- *Demand response processes shall be transparent; and*
- *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 through performance-based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions.*

We address the goal and the set of principles in detail below as they relate to party comments and other Commission directives.

In the May 20, 2016 Ruling, parties were asked what the Commission should expect demand response programs to accomplish, i.e. what should be the goal of demand response. The Ruling underscored that a goal is an overarching principle that guides decision making.[87] Parties were also asked whether the

[87] March 4, 2016 Administrative Law Judge Ruling at 4.

Commission should establish different goals for supply side versus load modifying demand response programs and/or for third-party supply resources versus utility supply resources.

Parties were generally in agreement regarding the need for one goal for both load modifying and supply side demand response. Most parties also recognized that demand response should reliably and efficiently meet the needs of the grid, in terms of transmission, distribution, system, local or flexible capacity needs.[88] Many parties specifically pointed out the need for demand response to be cost-effective.[89] SCE emphasized the need for demand response to reduce environmental impacts[90] while, along with several other parties, also underscored the need to address customer needs such as saving money or improved energy education.[91]

CESA and CLECA maintained that current and future demand response programs should refrain from focusing solely on traditional peak shaving duties and expand to address other needs such as ramping for renewable resources.[92] PG&E noted that, indeed, grid needs are evolving.[93] Furthermore, both Clean Coalition and NRG Energy, Inc. (NRG) discussed the necessity for demand

[88] See July 1, 2016 comments from AMS at 4, Clean Coalition at 2, TURN at 9, SCE at 2, PG&E at 5, OhmConnect at 1, and ORA at 1.

[89] See July 1, 2016 comments from CLECA at 3, Clean Coalition at 2, OPower at 3, ORA at 1 and SDG&E at 1.

[90] SCE July 1, 2016 Comments at 1.

[91] See July 1, 2016 comments from CAISO at 2, OhmConnect at 1, SCE at 2, SDG&E at 2, and PG&E at 5.

[92] CESA July 1, 2016 Comments at 4 and CLECA at 3.

[93] PG&E July 1, 2016 Comments at 5.

response programs to meet these evolving needs by moving toward a more coordinated effort with other distributed energy resources,[94] as is being addressed in R.14-08-013 and R.14-10-003.[95] These two proceedings will provide a methodology and framework for enabling the Commission to value distributed energy resources—such as demand response—on a level playing field and then provide a platform for competitively procuring the resources on an integrated basis. Hence, as we previously discussed, this decision does not address the issue of integrating demand response with other resources in this decision. Once R.14-08-013 and R.14-10-003 have developed and adopted the valuation methodology and integration solicitation framework, the goal and set of principles we adopt here will work side-by-side with the adopted methodology and framework. Furthermore, we also reiterate our prior discussion regarding the need for R.14-10-003 to consider whether policies supporting the integration of distributed energy resources should maximize grid benefits or customer participation and whether customer incentives should be uniform or differentiated by locational value.

Based upon the comments of the parties we adopt the following overarching goal for demand response programs regulated by the Commission:

> *Commission-regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost.*

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94 Clean Coalition July 1, 2013 Comments at 2 and NRG July 1, 2013 Comments at 3-5.

95 R.14-08-013 is addressing the development of the Utilities' distribution resource plans and R.14-10-003 is addressing the integration of distributed energy resources, including demand response.

Parties generally agreed that the issues of system reliability (i.e., grid needs), environmental needs (e.g., reducing the need to build more generators), and customer needs are the top attributes of demand response. In addition, parties also pointed out other important attributes of demand response. We find it reasonable to translate these attributes into a set of principles by which demand response programs should abide.

First, we begin with a discussion of the major attributes of the adopted goal: the needs of the grid, the environment and customers. In regard to environmental needs, parties recommend that programs should be consistent with the Commission's and the State's environmental policies.[96] While we include the environmental aspect in our adopted goal, we are more specific in our principle in that demand response shall support emission reductions and shall support the integration of renewables.[97] It is reasonable for the Commission to adopt such a principle. CESA and TURN suggest that demand response should be balanced with the needs of the grid in order to ensure reliability of the resource.[98] Several parties also suggest that incentives should be aligned with the changing needs of the grid.[99] Hence, we adopt the principle that demand response shall evolve to complement the continuous changing needs of the grid. The third attribute of the goal, customer needs, is further defined by our next principle which requires a focus on customers. Here, customer-oriented demand

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[96] *See* CLECA at 3; CAISO at 2; SCE at 2; and JDRP at 4.

[97] *See* July 1, 2016 Comments from CAISO at 2, CESA at 4, Clean Coalition at 2, and EDF at 8.

[98] *See* July 1, 2016 Comments from CESA at 4, Joint Demand Response Parties at 5-6, and TURN at 9-11.

[99] Joint Demand Response Parties July 1, 2016 Comments at 4.

response shall ensure that customers of demand response programs have a right to choose from all available products—whether those products be utility programs or third-party programs, are fairly compensated, and are empowered through education.[100]

The next two principles are descriptive in how demand response should act. Parties recommended a coordinated effort and suggested that demand response work in an organized fashion. For example, pricing signals could be provided through rate design.[101] Hence, we adopt the principle that demand response shall be coordinated with rate design. Lastly, several parties noted a concern that processes for determining load modifying and supply side resources are not clear to all stakeholders.[102] Furthermore, parties contend additional clarity could lead to opportunities to examine, comment upon, and improve decision making for the processes.[103] Hence, we adopt the principle that all demand response processes shall be transparent.

The last principle examines an attribute prevalent throughout this proceeding, that of an increased market focus. CAISO suggests that the Commission could spur innovation by promoting market-driven demand response solutions.[104] SDG&E, however, offers that new markets could create cross jurisdictional issues and suggests that accurate prices signals must be

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[100] *See* July 1, 2016 Comments from Nest at 3; Joint Demand Response Parties at 4, CAISO at 2 and AMS at 2.

[101] *See* CLECA July 1, 2016 Comments at 3.

[102] *See* July 1, 2016 Comments from Opower at 3 and EDF at 8.

[103] EDF July 1, 2016 Comments at 8.

[104] CAISO July 1, 2016 Comments at 2.

developed for demand response while current "carve outs" create an uneven playing field and should be eliminated.[105] We agree with CAISO that promoting market-driven demand response solutions is fundamental to growing reliable demand response. Within our "market-driven" principle we address what we consider to be the most important aspects of a market-driven demand response portfolio.

First, we agree in principal with the remark from SDG&E that demand response programs should be on a level playing field. However, we find that the playing field is uneven on several levels and until we can guarantee a balanced market, we will allow certain carve outs within reason. We explain this further in our discussion on the demand response auction mechanism. Parties suggest that demand response programs should be technology neutral and adopt technologically-agnostic solutions.[106] We agree and will continue to address this attribute here and in the integration proceeding.

Secondly, parties stressed the importance of program and customer reliability, noting the strict expectations of supply-side programs. ORA maintains that the current program requirements only reduce or eliminate payment for non-performance.[107] Proposing that demand response programs should have explicit requirements stated in the tariffs, ORA and CAISO suggested that these requirements could include performance standards, penalties, as well as enforcement mechanisms.[108] CAISO takes this one step

[105] SDG&E July 1, 2016 Comments at 2.

[106] *See* CAISO July 1, 2016 Comments at 2.

[107] ORA at 6.

[108] ORA at 6. *See* also CAISO at 4.

further and recommends that the Commission should open the market to allow more third-party providers to deliver grid services through competitive solicitations.[109] CAISO opines that a competitive framework can provide greater market transformation.[110] Hence, we adopt the following market-driven principle:

> *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 through performance-based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions.*

4.2.3. The Role of the Utility in the Future

In our set of principles we adopt in this decision, we include references to customer choice. We plan to ensure that a broad array of demand response options, including demand response provider options, is offered to customers. As we discuss below, it is the customers who should determine what role the Utilities will play in the future, through their selections from the various options that are provided. Utilities and third-party providers should fairly compete on a level playing field to vie for customers to enroll in their demand response programs. Furthermore, statistics measuring the success of the various new efforts we have embarked upon will materialize in the near future. But at this time, it is premature to dismantle the current demand response provider model where the utilities play the key administrative role.

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[109] CAISO at 4.

[110] *Ibid.*

One of the issues in this proceeding is to determine the role of the Utilities in both load modifying and supply side demand response programs.[111] Parties were asked to respond to questions regarding the evolution of the role of the Utilities and what the future role should entail.[112]

When demand response programs were established at the Commission, the Utilities were the natural providers of demand response programs with significant experience in marketing, outreach, and rate design.[113] The roles and responsibilities for Utilities and third-party providers have changed significantly over the years, especially with the introduction of CAISO market integration, direct participation in the CAISO market, and the demand response auction mechanism.[114] The full effect of these changes is unknown, so parties have recommended that the Commission should wait to make any changes to the role of the Utilities.[115] Several parties remarked that it is premature to address the future role of utilities and third-party providers when we do not have the results of the current activities such as the demand response auction mechanism and, therefore, cannot know the most appropriate role for the utility.[116]

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111 Joint Assigned Commissioner And Administrative Law Judge Ruling And Revised Scoping Memo, April 2, 2016 at 5.

112 Administrative Law Judge Ruling, March 4, 2016 at 5-6.

113 NRG Comments, March 18, 2016 at 2.

114 March 18, 2016 Comments from PG&E at 5, SCE at 6, and CESA at 4.

115 March 18, 2016 Comments from SCE at 6, Joint Demand Response Parties at 11-14, and SDG&E at 5.

116 March 18, 2016 Comments from California Energy Efficiency Industry Council (CEEIC) at 4, CLECA at 5, Joint Demand Response Parties at 11-14, PG&E at 6, and SDG&E at 5.

The Utilities maintain that they are uniquely qualified to manage portfolios to maximize the value of demand response and achieve state climate goals.[117] SCE suggested that the Utilities should continue to serve as administrators because they possess important electric system experience, proficiency in managing distribution level needs, and experience with customers and third-party providers.[118] NRG noted that, with the evolution toward market integration, limitations exist in the Utilities and underscored two in particular: 1) the Utilities' legacy systems, which were not designed to meet the current needs of the system; and 2) the lack of uniformity between the Utilities.[119] Because of these limitations, NRG recommended that more responsive and flexible entities should assume a greater role in providing services.[120] Even with the current limitations, Nest suggested that the Commission should continue the current role of the Utilities but also allow third-party providers to continue to implement their own programs. Nest further advocated that the Commission should let the customers decide, through the selection of programs in which they participate.[121]

Others suggested that the Commission should adopt a smaller role for Utilities in future.[122] Both CAISO and Shell advocated that the Commission transition from a utility provider model to a competitively procured framework,

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[117] March 18, 2016 Comments from PG&E at 6, SCE at 6 and SDG&E at 6.

[118] SCE March 18, 2016 Comments at 6.

[119] NRG March 18, 2016 Comments at 2.

[120] NRG March 18, 2016 Comments at 3.

[121] Nest March 18, 2016 Comments at 4.

[122] March 18, 2016 Comments from NRG at 3 and Shell at 3.

which would be more widely focused on overall grid needs to allow demand response to grow from a niche program model to a competitive market of diverse suppliers focused on serving the needs of the grid.[123] Because of the advantages of competitive procurement, ORA argues that demand response programs should be procured primarily via a mechanism similar to the demand response auction mechanism. However, ORA concedes there needs to be a transition period before utility-centric programs could be fully transitioned to a competitive procurement environment.[124] ORA therefore recommends a transition roadmap that includes first setting procurement goals, then capping supply demand response procured through utility provider programs while allowing the Utilities to retain management of load-modifying programs.[125]

Over the course of the past five years, the Commission has expanded not only the choice of demand response services and programs, but the choice of providers. The Commission is encouraged with the increased level of interest by customers participating in these choices, but we recognize that these efforts are new. Statistics measuring the success of the various new efforts will begin to materialize. However, we agree with other parties that it is premature to dismantle the current demand response provider model where the utilities play the key administrative role.

Several parties advocate for the Commission to transition the role of the Utilities from program provider to a smaller role. We return to the set of principles we adopt in this decision and concentrate on two aspects, that of

[123] March 18, 2016 Comments from CAISO at 4 and Shell at 3.

[124] ORA March 18, 2016 Comments at 7.

[125] *Id*. at 5-8.

competitive neutrality and that of consumer choice. The experience of the Utilities in this field should not be ignored. Ratepayers have invested a great deal of time and money in order for the Utilities to gain this experience. Because we have adopted a principle of market-driven demand response with a focus on competition, we will encourage the use of fair competition between the Utilities and third-party providers in demand response and will adjust accordingly to the outcomes of the competition. Furthermore, our principle of consumer choice dovetails with this principle. We plan to continue offering a broad array of demand response options to customers, including the option of either the Utilities or third parties providing these services. We find that customers should determine the eventual role the Utilities will play in the future, through the customers' selections from the various demand response options that are provided. Hence we find it reasonable to continue both roles of the Utilities as demand response program providers (implementers) and administrators. However, in order to improve competition for the third-party providers in this nascent world, we separate the roles, as further described in our guidance for 2019 demand response portfolios.

4.2.4. Program Budget Cycle Length

We adopt a budget length of five years in order to create market stability, sustain momentum and performance. Furthermore, with this first longer cycle portfolio, we establish a mid-cycle review in 2020.

Joint Demand Response Parties contend that longer cycles are a double edged sword because aggregators must continue to attract and retain participation in programs due to the difficulty to predict two to three years into the future.[126] If the ten-year cycle allows for flexibility, the Joint Demand Response Parties state that it could be acceptable but a ten-year contract to perform would put aggregators in a tenable situation.[127] While Joint Demand Response Parties agree that longer budget cycles may allow demand response resources to be better incorporated into a long term planning process; mid-course corrections must be included.[128]

Energy Efficiency Council maintains that the ten-year cycle has had an immediate impact on the credibility of energy efficiency as a procurement resource in the marketplace.[129] Both CESA and NRG support the ten-year cycle, as adopted in the energy efficiency proceeding.[130] Pointing to a reduced administrative burden, CESA also noted that opportunities for mid-course adjustments to reflect market conditions are available.[131] While supporting a ten-year cycle, SCE cautioned that the ability to respond to market and policy changes is challenging.[132] SCE, therefore, suggested that the commission adopt triggers to respond to policy changes or market conditions. Noting that some parties may not feel comfortable with the level of risk involved in a ten-year cycle, SCE stated that it would support a five-year cycle.[133] PG&E also supports

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[126] Joint Demand Response Parties, March 18, 2016 Comments at 15.

[127] *Id.* at 15-16.

[128] *Id*. at 16. *See also* SCE at 8-9.

[129] California Energy Efficiency Industry Council, March 18, 2016 Comments at 6.

[130] NRG March 18, 2016 at 4.

[131] CESA March 18, 2016 Comments at 6.

[132] SCE March 18, 2016 Comments at 8-9.

[133] SCE at 9.

the longer budget cycle but recommends a five-year cycle emphasizing that longer budget cycles require greater flexibility to revise budgets as programs evolve.[134]

PG&E, ORA and SDG&E suggest that the Commission take a wait and learn approach regarding the energy efficiency ten-year budget cycle.[135] ORA contends that demand response is not suitable for longer budget cycles, which are more conducive for stable programs that do not require substantive changes.[136] ORA notes that DR customers are not locked in to any long-term program or contract beyond one year.[137] SDG&E also opposes the ten-year cycle, agreeing that energy efficiency and demand response are very different but more because demand response is going through such great changes. However, SDG&E supports the five-year cycle.[138] CAISO opposes the extension of the budget cycles and instead calls for the Commission to move away from program portfolios and transition solely to competitive solicitation framework beginning in 2018.[139] We agree that there has not been sufficient time to ascertain the success of the energy efficiency ten-year rolling portfolio. Given the multiple changes to the demand response program, we consider it prudent to adopt a five-year cycle.

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134 PG&E March 18, 2016 at 6-7.

135 March 18, 2016 Comments from ORA at 10, PG&E at 6-7, and SDG&E at 10.

136 ORA March 18, 2016 Comments at 10.

137 *Ibid*.

138 SDG&E, March 18, 2016 Comments at 10.

139 CAISO March 18, 2016 at 6.

Similar to the energy efficiency portfolio, we recognize the potential need for the Commission to address issues that occur within the five year cycle.[140] I the energy efficiency portfolio, the Commission adopted the requirement that energy efficiency program administrators must file an application when a trigger event occurs, e.g. a policy change or a budget conflict. The success of this process has not been determined. Hence, for the first five-year cycle, we will adopt a mid-cycle review in 2020. Below, we describe the mid-cycle review with the caveat that this process shall be reviewed in the application for 2023-2027 demand response portfolios.

The mid-cycle review shall begin with a tier three advice letter filing by each of the Utilities on April 1, 2020 providing a full status report of each demand response program and recommending changes to the programs in response to any problems with the programs. Parties will have an opportunity to review and respond through the advice letter process. The Commission's Energy Division will then address the advice letter and party comments through a Resolution provided to the Commission no later than September 30, 2020. This schedule will provide the Utilities sufficient time to implement any changes for the 2021-2022 program years.

Applications for 2023-2027 demand response portfolios shall be filed by each of the Utilities no later than November 30, 2021.

Lastly, we reject the CAISO's recommendation to transition solely to competitive solicitations. While we share the CAISO's goal and find that the demand response auctions show promise, it is premature to conclude

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[140] *See* D.15-10-058 at Finding of Fact 15 where the Commission determined that it needs more opportunities to weigh in via decision or resolution.

competitive solicitations should be the sole means of sourcing demand response. In our guidance below, we outline a path which progresses our consideration of this issue.

4.3. Guidance to Utilities for 2018 Demand Response Applications

In this decision, we have provided guidance to the Utilities and other demand response stakeholders in the form of an adopted goal and set of principles for demand response programs. We have also indicated that the demand response applications to be filed by the three demand response utilities on January 16, 2017 should cover the years 2018 through 2022 but only address current models of demand response programs. As detailed below, many of the changes we anticipate with the current programs are already in process with the adoption of past decisions in this proceeding: D.14-12-024, D.15-11-042 and D.16-06-029. Furthermore, we also explain the interaction between this proceeding and the proceedings regarding the Distribution Resource Plans (R.14-08-013) and, more directly, the Integration of Distributed Energy Resources (R.14-10-003), as well as the Integration Resource Planning proceeding (R.16-02-007). We describe below how these rulemakings will provide a framework for demand response to work together with other distributed energy resources to ensure grid reliability for California customers. This section provides guidance regarding the future of the demand response auction mechanism pilot and the steps to be taken to transition, if appropriate, from pilot status. Lastly, this section addresses some additional miscellaneous matters related to the future portfolios.

4.3.1. Continuing Down the Established Path

In September 2013, the Commission commenced this rulemaking to enhance the role of demand response in meeting the State's resource planning needs and operational requirements. Our intention was to prioritize demand response as a utility-procured resource competitively bid into the CAISO energy market. The Commission considered it necessary to retool demand response to align with the needs of the grid.

Working through the issues as set forth in the Scoping Memos, we first determined in D.14-03-026 that we would review the current utility-administered ratepayer-funded demand response programs as load modifying resources or supply side resources competitively bid into the CAISO wholesale electricity market.[141] In D.14-12-024 and D.15-02-007 the Commission adopted a joint party proposal,[142] which established working groups and the performance of a demand response potential study. The decision required full implementation of the bifurcation of demand response programs by 2018 (and hence, full integration of supply side resources into the CAISO market), with 2016 and 2017 denoted as transition years. Lastly, the decision required the design and implementation of a demand response auction mechanism pilot.

Less than a year later, the Commission solidified its commitment to the integration of demand response into the CAISO market by first concluding that event-based load modifying resources have no measureable capacity value and

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141 D.14-03-026 defines load modifying resources as resources that reshape or reduce the net load curve and supply resources are demand response resources that are integrated into the CAISO energy market. *See* D.14-03-026 at Ordering Paragraphs 2 and 3.

142 D.15-02-007 amended D.14-12-024 to change the term "settlement agreement" to a joint proposal.

thus requiring that only demand response programs integrated into the CAISO energy market or embedded in the California Energy Commission's unmanaged/base case load forecast will receive capacity value.[143] Disputing the claim that this would harm the Commission's demand response programs, D.15-11-042 provided an exhaustive list of efforts to grow and improve non-event based load modifying resources as well as supply side resources. We reiterate this list here:

1. Efforts to address technical or policy barriers to CAISO market integration;
2. Enabling third-party demand response providers through the implementation of direct participation into the CAISO market;
3. Demand Response Auction Mechanism pilots;
4. Demand Response Potential Study;
5. Default Residential Time-of-Use Rates;
6. Local Capacity Requirements procurement activities; and
7. Distribution Resources Plan and Integrated Distributed Energy Resources Proceedings.

Earlier this year, the Commission approved D.16-06-029, which adopted bridge funding for 2017 demand response programs and activities. As directed in D.14-12-024, the 2017 program year is considered the final of two transition years. In adopting bridge funding for 2017, the Commission succeeded in attaining significant improvements to demand response programs. Those improvements include:

1. Near completion of bifurcation and CAISO market integration of demand response supply side programs in 2017;

[143] D.15-11-042 at Ordering Paragraph 1.

2. Near consolidation of all demand response programs, tariffs and incentives (exemption of rate programs) in 2017 and complete consolidation required in 2018 applications;
3. Elimination of Demand Bidding Program beginning in 2017 (2018 for SCE due to Aliso Canyon Crisis) due to incompatibility with CAISO market integration;
4. Elimination of PG&E's Aggregator Managed Portfolio (AMP) program and their contracts beginning in 2017 and limitation of SCE's AMP contracts to one year through 2017;
5. Adoption of statewide standards for Automated Demand Response Program beginning in 2017; and
6. Authorization of 2017 Demand Response Auction Mechanism pilot auction for 2018 delivery, require the bids fit portfolio needs and offer best value to the ratepayer.

We require the Utilities to continue the improvements described in this section as well as all other utility-specific improvements described in D.16-06-029 and complete the efforts of bifurcation, demand response direct participation in the CAISO market, and the integration of current models of demand response programs into the CAISO market. Furthermore, as set forth below, the Utilities shall build upon the improvements.

In a May 20, 2016 Ruling, parties were asked to comment on further improvements to the design of demand response programs and performance of customers. In addition to the improvements the Commission directed for 2016 and 2017, we focus this decision on guidance for the Demand Response Auction Mechanism but also provide guidance on miscellaneous matters below.

4.3.2. Demand Response Auction Mechanism

We begin with a discussion regarding the current demand response auction mechanism pilots. D.16-06-029 recognized that the demand response auction held in 2015 experienced robust responses and is considered successful in engaging third-party service providers and customers. However, the Commission concluded and most parties concede that until a review of the pilot's delivery performance results can occur, the Commission cannot consider its full merits.[144] The Commission, therefore, ordered a third pilot, with the auction to be held in 2017 and delivery in 2018.[145]

4.3.2.1. Transitioning the Demand Response Auction Mechanism from Pilot to Fully Operational Mechanism

In determining whether and when to transition from pilot status, we turn to our objectives for considering a competitive procurement process: ensuring cost-effective and reliable demand response resources for California and engaging new third parties and customers.[146] To move from pilot status the auction mechanism must be deemed successful. Below, we consider the elements we should measure to gauge the success of this pilot.

In responses to the May 20, 2016 Ruling, we review the comments with a focus on ***measurable*** (emphasis added) recommendations. TURN, for example, contends that performance will depend on actual enrollment of customers who can provide real demand response and successful integration with the CAISO market.[147] OhmConnect asks the Commission to review the level of engagement by third parties.[148] CAISO maintains that the Commission should focus on

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[144] See, for example, CESA July 1, 2016 Comments at 16, CLECA July 1, 2016 Comments at 15; SCE July 1, 2016 Comments at 17, and TURN July 1, 2016 Comments at 21.

[145] D.16-06-029 at Ordering Paragraphs 19 and 21.

[146] OIR at 18.

[147] TURN, July 1, 2016 at 21.

[148] OhmConnect, July 1, 2016 at 11.

whether procurement contracts are fulfilled and performance expectations are met.[149] SCE states that because the auction mechanism is intended to be a competitive procurement mechanism, metrics should measure the robustness of the auction.[150] SCE goes on to explain that the Commission should consider how well the pilot meets its primary objectives, namely: a) the feasibility of procuring supply-side resources for resource adequacy with third-party direct participation in the CAISO markets, and b) the ability of winning bidders to effectively integrate their resources into the CAISO market.[151] Joint Demand Response Parties note that the Commission approved a set of metrics for evaluating the pilot after the delivery periods.[152]

We agree that in considering whether to expand its role in the resource adequacy market, we should review whether the pilot met key objectives, especially those assessing third party and customer engagement, the competitiveness of prices, and reliability of the demand response. Accordingly, we find it reasonable to adopt the following criteria for determining the success of the demand response auction mechanism: a) Were new, viable third-party providers engaged; b) Were new customers engaged; c) Were bid prices competitive; d) Were offer prices competitive in the wholesale markets; e) Did demand response providers aggregate the capacity they contracted, or replace it with demand response from another source in a timely manner; and f) Were

149 CAISO July 1, 2016 at 5.

150 SCE, July 1, 2016 at 18.

151 SCE July 1, 2016 Comments at 17.

152 Joint Demand Response Parties, July 1, 2016 at 28 citing SCE Advice Letter 3208-E, PG&E AL 4618-E, and SDG&E AL 2729-E, at 22-24.

resources reliable when dispatched, i.e., did customers perform appropriately. The Energy Division analysis should include a review of these criteria by customer class. We will treat these criteria as objectives that the demand response auction mechanism must meet in order to expand its role in the resource adequacy market.

The demand response auction mechanism pilot review process should ensure transparency and due process to stakeholders. We find the following steps to provide transparency and due process and, therefore, are reasonable:

1. First, we authorize the Commission's Energy Division to conduct an independent analysis of the results of the 2015 and 2016 pilot auctions and the subsequent deliveries, emphasizing the five criteria above. Energy Division is authorized to access demand response research funds approved by the Commission in D.12-04-045 and D.16-09-029, if consulting expertise is necessary for the analysis.

2. To ensure transparency, Energy Division is required to hold a workshop no later than January 31, 2017. The purpose of the workshop is for Energy Division to present the proposed metrics and evaluation plan it will use for the assessment of the criteria. Parties will be provided an opportunity to comment on the metrics and evaluation plan.

3. No later than April 1, 2017, the Energy Division will provide a public report on its final list of metrics and evaluation plan, based on the workshop and party comments.

4. Energy Division will then perform its analysis and present its findings and recommendations on whether to proceed from a pilot to permanent implementation of the mechanism to the Commission through a resolution. The draft resolution shall be issued no later than June 1, 2018. This timing will allow the Energy Division to review the results of all three auctions, delivery statistics from 2016 and 2017, and preliminary delivery statistics from the summer of 2018.

If the Commission approves full implementation of the demand response auction mechanism, the timing of these review steps will allow the Utilities to begin administering annual auctions in 2019 for 2020 and beyond delivery. If approved, Energy Division will hold a workshop 30 days after the issuance of the resolution approving the transition from pilot status. The purpose of the workshop will be to discuss the advice letter process for approving the implementation of the future auction mechanism and to ensure the implementation process complies with this decision. The Utilities will have 60 days after the workshop to file the tier one advice letter requesting Commission approval of the implementation of the demand response auction mechanism. The first auction shall be held in the spring of 2019 for 2020 delivery. We now address what we expect a fully implemented demand response auction mechanism to entail.

4.3.2.2. Permanent Demand Response Auction Mechanism Requirements

Consistent with our market-driven principle adopted in this decision, we establish a policy that a demand response auction mechanism program, administered by the Utilities, will become a primary means of sourcing demand response in the future. To facilitate this transition, annual funding for all demand response load modifying and supply resource programs provided by the Utilities, not including funds to administer the demand response auction mechanism, shall be capped at 2017 budget levels until 2020, the mid-cycle program review; all additional demand response shall be sourced through the auction mechanism. We clarify that we anticipate the Utilities' portfolios to continue to evolve and improve, within the annual budget limitations, in order to compete for customers in the expanding demand response market. The size of new demand response sourced through the auction mechanism shall reflect the competitiveness of bids as described below. To ensure the neutrality of the auction, further development of competitive third-party aggregators, and the shift of performance risk away from utility ratepayers toward third parties, the Utilities are prohibited from participating in the auction mechanism. Additionally, we improve the reliability of demand response sourced through the auction mechanism by requiring the same penalty structure as resource adequacy contracts and by offering a range of contract lengths from one to five years. We discuss these policies in more detail below.

As described in the previous discussion and indicated by the July 1, 2016 comments, we find strong support for growing the demand response auction mechanism.[153] Parties provided descriptions of their vision of what the program would resemble. The CAISO, ORA, and OhmConnect each suggested that the auction mechanism should become the main procurement mechanism for resource adequacy capacity from all demand response supply sources.[154] CAISO contends that opening demand response markets to allow third-party providers to deliver grid services through a competitive procurement framework results in greater market transformations. SDG&E provided a slightly different view, stating that demand response resource adequacy resources should participate with other resources in a competitive all-source resource adequacy solicitation.[155]

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[153] *See*, for example, EDF July 1, 2016 Comments at 8, PG&E July 1, 2016 Comments at 29.

[154] CAISO July 1, 2016 Comments at 4, ORA July 1, 2016 Comments at 9-10, OhmConnect July 1, 2016 Comments at 10.

[155] SDG&E July 1, 2016 Comments at 36. DG&E also explained that auctions should be structured to ensure demand response providers are providing firm resource adequacy capacity with damages consistent with other resource adequacy contracts.

The Utilities and CAISO contend that the Utilities are best able to assess and deploy demand response solutions to offset the need for traditional distribution upgrades.[156] ORA suggested that the role of the Utilities should be solely focused on facilitating direct participation in the CAISO market.[157]

While others called for a transition from utility oversight,[158] we agree with PG&E that that there is insufficient information to conclude whether the auction mechanism would be more successful under the administration of a third party.[159] In response to the concern voiced regarding a perceived conflict with having the Utilities oversee the demand response auction and simultaneously promoting their own demand response programs,[160] we adopt two measures to moderate the Utility role: 1) capping funding for Utility programs, and 2) prohibiting the participation of utility provider programs in future auction mechanisms. As described by ORA, the Commission review process allows discussion of bids at the Procurement Review Group meetings, where the Commission's Energy Division, ORA, TURN and other non-market participants can discuss and provide input.[161] Furthermore, the Commission itself maintains

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156 CAISO July 1, 2016 Comments at 4.

157 ORA July 1, 2016 Comments at 2-3 and 5.

158 EDF July 1, 2016 Comments at 6, Joint Demand Response Parties July 1, 2016 Comments at 36 and OhmConnect July 1, 2016 Comments at 2.

159 PG&E, July 15, 2016 Reply Comments at 4. PG&E explains that EDF's comparison of the CAISO and PJM markets are misguided as the CAISO does not have a centralized capacity market. Furthermore, PG&E also expressed concern that a centralized capacity market could have jurisdictional implications for the Commission.

160 Joint Demand Response Parties, July 15, 2016 Reply Comments at 5.

161 ORA July 15, 2016 Reply Comments at 4.

the authority and capacity to ensure the Utilities administer the auction in a fair manner.

In our earlier discussion on the role of the Utilities, we concluded that the Utilities should continue in their two roles as program providers and administrators. However, we also noted our concern about the competition playing field not being level at this time. Creating a separation between the two utility roles and allowing the continuation of both sets of programs will address our principles of competition and customer choice. Accordingly, we find it reasonable to establish a policy that the demand response auction mechanism shall be administered by the Utilities and serve as the main procurement mechanism for resource adequacy capacity from all third-party demand response supply sources.

We also find it reasonable to require that the demand response programs provided by the Utilities shall not participate in the auction mechanism and annual funding for these activities shall be capped at 2017 budget levels until the mid-cycle program review. This cap does not include the costs to increase the number of customer registrations pursuant to Electric Rules 24 and 32.[162, 163] In comments, SCE requested that the budget cap be set for the entire budget cycle to provide flexibility. Providing such a wide degree of budget flexibility does not equate to providing a level playing. Hence, we require that the 2018-2022 demand response budget and activities applications filed by the Utilities contain

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162 Electric Rule 24 (PG&E and SCE) and Electric Rule 32 (SDG&E) establishes the requirements regarding the third party direct participation of demand response in the CAISO energy markets.

163 D.16-06-008 directed the Utilities to request additional funding for increasing the number of CAISO registrations, up to mass market numbers, in the demand response budget applications.

annual budgets of no more than the 2017 demand response budget, not including costs for the demand response auction mechanism.

Nothing precludes the Utilities from procuring demand response through other competitive solicitations. However, such procurement does not eliminate the requirements set forth in this decision. As a matter of policy, the Commission adopts the use of the demand response auction mechanism as a primary tool to fulfill its goals of expanding the role of demand response and expanding the role of third-party providers.

In regard to contract length, no party advocated for less than three year terms for winning bidder contracts, noting the inefficiency of the one-year contracts.[164] Several parties supported up to five-year contracts. SDG&E suggested that providers should have the latitude to offer various contract lengths in order to enable the most economic program possible but any term greater than five years should be viewed critically to ensure resources are price based on changing market conditions.[165] Similarly, PG&E proposed that capacity solicitations for the demand response auction mechanism be staggered across multiple years with certain products offered in one-, three-, or five-year terms to allow for risk mitigation for both the buyers and sellers.[166] The program should offer providers and customers as much flexibility as is possible and decrease the risk involved. Hence, we allow providers to offer contracts with ranges from one to five years. Capacity procured through contract terms one year or greater may be counted toward the annual obligations established for each utility.

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164 *See* SCE at 16, Joint Demand Response Parties at 28, AMS at 11.

165 SDG&E at 36.

166 PG&E at 32. *See* also OhmConnect at 10.

We improve the reliability of demand response sourced through the auction mechanism by requiring the same penalty structure as resource adequacy contracts, which is an obligation to replace resource adequacy capacity not delivered. If the Seller cannot deliver the capacity under the contract then they have an affirmative replacement obligation. If the Seller cannot provide adequate replacement demand response, it is appropriate to apply financial ramifications on the Seller. This obligation should ensure protection for the procuring load serving entity as well as the ratepayers. Furthermore, beginning in 2018, third parties bidding into wholesale markets will face penalties for failing to fully offer their capacity into the CAISO wholesale market under the Resource Adequacy Availability Incentive mechanism. This combination of potential penalties should ensure that ratepayers are not financially liable if contracted capacity is not delivered. The third-party provider's obligation to offer all available capacity into the CAISO wholesale market may be enforced.

At this time, we also maintain the 20 percent set-aside for residential customers. PG&E and SDG&E recommended that the Commission eliminate the residential set-aside requirement in the fully bifurcated demand response arena contending that it is more important to have the discretion to choose the most economical bids regardless of whether the bids are residential or non-residential and that DRAM resources should be competing not only with other resources through the resource adequacy solicitation, but also with the utility supply resource demand response which the utilities provide.[167] We see a need to allow

[167] SDGE July 1, 2016 Comments at 38 and PG&E July 1, 2016 Comments at 35.

this residential sector to grow and learn in this competitive environment before removing its "training wheels."

In determining the size of the program, many parties expressed the opinion that the auction mechanism should be sized to enable the Utilities to meet its needs or the Commission to meet its overall requirements for demand response from supply resources.[168] Other parties argued against setting a size based on a megawatt target or a budget amount.[169] Furthermore, the Joint Demand Response Parties contend that the size of the mechanism has to be of a size and scale that will replace the aggregator managed portfolio program…a couple hundred megawatts combined in the PG&E and SCE territories.[170] TURN suggests that the Utilities purchase as much demand response as can be provided through the auction mechanism, as long as the capacity payments under the mechanism are lower than a transparent cost- effectiveness benchmark, and lower than utility tariffed programs that provide the same products and value.[171]

We find that the size of the mechanism should be flexible based on the competitiveness of the bids received. The Utilities are directed to offer annual auctions and must offer contracts to all complying bids up to the simple average August capacity bid price. The simple average bid price shall be calculated by (1) excluding the top 10 percent of August bids offered then (2) totaling all

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[168] OhmConnect July 1, 2016 Comments at 10, SDG&E July 1, 2016 Comments at 36, PG&E July 1, 2016 Comments at 29.

[169] Joint Demand Response Parties July 1, 2016 Comments at 26, SCE July 1, 2016 Comments at 15-16 and AMS July 1, 2016 Comments at 11.

[170] Joint Demand Response Parties July 1, 2016 Comments at 26-28.

[171] TURN July 1, 2016 Comments at 21.

remaining August bid prices and (3) dividing by the number of bids in (2). This obligation is limited in three ways:

1) the Utilities shall not be obligated to procure more than one gigawatt statewide annually (allocated as 400 megawatts for PG&E and SCE and 200 megawatts for SDG&E);

2) the Utilities shall not be obligated to accept bids priced above the long term avoided cost of generation at the time of the auction;[172] and

3) the Utilities shall not award contracts to bids in which non-August capacity prices are outliers, e.g., a bid is below average in August but exceptionally high in March. The Utilities shall make such exceptions in consultation with its Procurement Review Group and the Energy Division.

This obligation should ensure that the auction mechanism provides substantial growth opportunity for performance-based demand response. Limiting procurement to the simple average August bid price should encourage competitive bidding behavior. Finally, the adoption of the one gigawatt ceiling and the known price benchmark should protect ratepayers. We clarify that if less than one gigawatt of eligible bids are priced at or below the simple August bid price, all offers below the average price earn a contract. If more than one gigawatt is offered at a price at or below that average, the most cost competitive contracts based on August capacity prices are accepted up to one gigawatt of August capacity.

We reiterate that the guidance provided here about future demand response auction mechanism procurement of demand response resources may

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[172] The Utilities shall use the long term avoided cost of generation used in the most recent avoided cost calculator update, pursuant to D.16-06-007.

require additional refinement by the Commission depending upon decisions in R.16-02-007, R.14-10-003, and R.14-08-013.

Furthermore, in order to assure the demand response auction mechanism is working properly and continues to meet its goals, the Energy Division will perform a routine review of the mechanism. Beginning in 2022, Energy Division will hold a workshop to discuss the demand response auction mechanism and, based on workshop feedback, determine whether it should recommend changes to the Commission.

Upon Commission approval of full implementation of the demand response auction mechanism, the Utilities are authorized to record contract and administration expenses resulting from the administration of the demand response auction mechanism in the Distribution Revenue Adjustment Mechanism for PG&E, the distribution sub-account of the Base Revenue Requirement Balancing Account for SCE, and the Advanced Metering and Demand Response Memorandum Account for SDG&E. This will enable the Utilities to procure demand response resources on an annual basis through the auction mechanism and allow up to five-year contracts without the confines of a budget cycle.

4.3.3. Miscellaneous Guidance for 2018-2022 Portfolios

4.3.3.1. Cost Effectiveness Protocols and Motion to Approve Permanent Load Shifting Working Group Recommendations

The Utilities are directed to utilize the 2015 Demand Response Cost Effectiveness Protocols (Protocols), as adopted in D.15-11-042, using the Renewable Electricity Capacity Planning (RECAP) methodology as the interim methodology for the A Factor.

In D.15-11-042, the Commission adopted the Protocols. Relevant to this decision, the Commission also 1) approved the future development and adoption of a probabilistic reliability model to replace the current utility-calculated Availability or "A" Factor but required a workshop to be held to discuss the potential use of the RECAP model in the interim; and 2) determined that the Protocals are not a good model for measuring the cost-effectiveness of the permanent load shifting program and therefore established a working group to propose an appropriate model. On May 27, 2016, the working group filed a motion to review and approve the permanent load shifting working group report.

A June 17, 2016 Ruling asked parties to respond to questions on these two issues. Parties were asked whether the Commission should adopt the RECAP methodology as its interim A Factor and allow additional methodologies for enhancement purposes. PG&E, SDG&E, SCE and the Joint Demand Response Parties all agree that the RECAP should be the interim A Factor. Joint Demand Response Parties note that they not support the use of the Effective Load Carrying Capability methodology applied to demand response resources, as a formal proposal has not been submitted for consideration in any docket. PG&E and SDG&E also state that the Commission should allow the Utilities to provide methodologies in addition to the RECAP methodology; Joint Demand Response Parties do not object but states that the filing should include the results of each methodology and the rationale for selecting one over the other should be transparent and subject to public examination. No other party responded to this question. We find it reasonable to adopt the RECAP methodology as the interim A Factor methodology. The Utilities may provide an alternate methodology in addition to the RECAP methodology, but the results of the methodology shall be transparent.

The permanent load shifting cost-effectiveness methodology working group report requests the Commission to adopt the following:

Table 1

Recommendations from PLS Cost-Effectiveness Working Group Report

Protocol Element	Working Group Findings
A Factor	Calculation of the A Factor should be the same as in the adopted Protocols.
B Factor	The B Factor, a dispatchability adjustment, is not applicable to PLS and should be omitted.
C Factor	The C Factor, an applicability adjustment of avoided capacity cost, is not applicable to PLS and should be omitted.
D Factor	Calculation of the D Factor should be the same as in the adopted Protocols until such time as a finalized locational net benefits methodology is adopted in R.14-08-013. At that time, the Protocols should be adjusted to reflect the adjusted avoided transmission and distribution costs.
E Factor	Should equal 100 percent for PLS, as it is a magnitude adjustment of avoided energy cost.
F Factor	The F Factor, a bonus for offering flexible capacity, is not applicable to PLS and should be omitted.
G Factor	The G Factor, a bonus for locating in geographically preferred areas, should follow the adopted Protocols' instructions.
Avoided Costs	The avoided generation capacity cost and avoided transmission and distribution cost should be applied using avoided costs for each year of the technology's useful life rather than a single levelized number to yield a more precise calculation of cost-effectiveness for PLS.

No party opposed these recommendations. The recommendations were generated through several meetings of the working group represented by the Utilities, Energy Division, the consultant, E3 and multiple stakeholders. We find the recommendations to be reasonable and should be adopted.

4.3.3.2. Exception Dispatch Reporting

The Utilities are relieved of the requirement to provide weekly demand response exception reports beginning on January 1, 2017. As described below, the reports are no longer necessary given that the majority of demand response programs are to be bid into the CAISO market and CAISO will determine when programs are dispatched.

D.14-05-025 and Resolution E-4708 required the Utilities to provide weekly demand response exception reports in order to provide transparency regarding the decisions the Utilities make in determining whether or not to dispatch a demand response program when a program trigger is met. In the May Ruling, parties were asked whether the Commission should require the Utilities to continue to file the weekly demand response exception reporting. PG&E, SCE and ORA all agreed that, given the integration of demand response into the CAISO market, the weekly exception reporting would no longer be necessary.[173] SDG&E recommends filing the report on a monthly basis for those programs not integrated into the market.[174]

The majority of demand response supply side programs will be bid into the CAISO market beginning in 2017, with the remaining programs required to

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[173] PG&E July 1, 2016 Comments at 43-44; SCE July 1, 2016 Comments at 29-30; and ORA July 1, 2016 Comments at 13.

[174] SDG&E July 1, 2016 Comments at 46.

be integrated no later than January 1, 2018. The CAISO will determine whether a demand response resource is dispatched. We find the weekly demand response exception reporting to no longer be necessary. It is reasonable to relieve the Utilities of the requirement to provide the weekly exception reports.

4.3.3.3. Petition for Modification

The Commission denies the Petition for Modification filed by the Joint Petitioners requesting that the Commission modify Ordering Paragraphs 4.f.i. and 4.f.iii. of D.14-12-024 and authorize the continuation of the Integration Working Group and the Operations Working Group. As further described below, the proposed work to be conducted in these two groups either can be conducted by processes already in place, both at the Commission and the CAISO, or has already been conducted.

The Joint Petitioners ask the Commission to allow the Integration and Operations Working Group to continue to operate because important implementation matters require further investigation and resolution. The Joint Petitioners specify that the Integration Working Group should continue working on baseline and statistical sampling proposals and the analysis of differences between retail and wholesale baselines. The Joint Petitioners recommend that the Integration Working Group could be directed to submit a July 1, 2016 report on the baseline proposals and the analysis regarding the differences between retail and wholesale baselines. In regards to the Operations Working Group, the Joint Petitioners recommend that it should continue to operate in order to address the potential need for future changes in operations including recalibrations to reports and processes, the implications for hard triggers, potential changes to forecast templates, sharing lessons learned on supply resource market awards, and potential issues regarding dual use demand response programs and resources. The Joint Petitioners recommend a final report to be filed by the Operations Working Group no later than January 5, 2017.

Issues regarding hard triggers are now irrelevant given the Commission's November 19, 2015 decision not to adopt any hard trigger proposals.[175] Furthermore, as described in the CAISO protest, the Commission and the CAISO have processes in place for vetting and deciding demand response integration issues. The CAISO contends that the generalized issues listed in the Petition can be addressed through these existing processes. In its Petition, the Joint Petitioners concede that the proposed work could be done either through an extension of the working group or some other auspices.[176] The CAISO specifies in its protest that the work recommended to be done through the continuation of these two working groups can be accomplished through CAISO operations staff, a formal CAISO stakeholder process, or formal Commission proceedings.[177]

We find that it is duplicative, and therefore unreasonable, to continue the work of the Integration and Operations Working Groups when the same work has been or can be accomplished by existing CAISO or Commission processes. Hence, the Commission should not grant the Petition to continue the Integration and Operations Working Groups. Accordingly, the Commission should also make no changes to D.14-12-024, Ordering Paragraph 4(f.)

5. Comments on Proposed Decision

The proposed decision of Administrative Law Judge Hymes in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities

[175] D.15-11-042.

[176] Petition at 2.

[177] CAISO Protest at 4-5.

Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on September 19, 2016 by CEEIC, CESA, Comverge, CLECA, Bloom Energy, Joint Demand Response Parties, OhmConnect, Opower, ORA, PG&E, SCE, SDG&E, Sierra Club/EDF, Solar City, and TURN. Reply comments were filed on September 26, 2016 by Bloom, CAISO, CLECA, Joint Demand Response Parties, ORA, OhmConnect, OPower, PG&E, SDG&E, Sierra Club/EDF, SoCalGas, SCE and TURN. Clarifications and corrections were made throughout this decision in response to the comments. We address certain comments here.

SCE requested a 30-day delay in filing 2018-2022 demand response budget and activities applications. Noting that it received 4.5 months to develop 2017 bridge funding applications, SCE contends three months is insufficient time to develop a more difficult five-year application.[178] We provide a 15-day extension and require the Utilities to file applications no later than January 16, 2017.

Parties asked for clarification regarding whether the Utilities will be providing the new models of demand response or whether third party providers will be providing them through the demand response auction mechanism. This decision should be made following the issuance of the second part of the 2015 demand response potential study. Hence, the decision has been revised to eliminate any proposed schedule regarding new models of demand response programs.

[178] SCE Comments to the Proposed Decision at 11.

Parties express concern over the continuation of the Utilities performing as the administrator of the demand response auction mechanism.[179] While we determine that it is reasonable for the Utilities to continue to perform this role, it is prudent to review this determination on a regular basis as part of an overall review of the demand response auction mechanism. The decision has been revised to adopt a routine review.

CLECA requests the Commission to permit a replacement program for the Demand Bidding program that was discontinued in 2017. CLECA argues that without this program, participants will lose the opportunity to provide price-based demand response.[180] We confirm that there is nothing that precludes a utility from developing a program that would allow this set of customers to participate in demand response. The Utilities are encouraged to develop new programs or evolve current ones within the budget confines we adopt herein.

SCE stated that there is not an industry standard for contacts or penalty structures.[181] SCE recommended language similar to a "Firm" agreement. In reply comments, the CAISO supported this addition, stating that the language will "ensure the [demand response auction mechanism] contract clearly requires providers to show, deliver, and replace, as necessary, their contracted [resource adequacy] capacity and not leave to the CAISO to resolve through backstop and penalty provisions. We find this requirement complies with our adopted goal and principle of reliable demand response and we adopt this above.

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179 *See*, for example, Sierra Club/EDF Opening Comments on the Proposed Decision at 7-8.

180 CLECA Opening Comments on the Proposed Decision at 3-4.

181 SCE Opening Comments on the Proposed Decision at 8-9.

6. Assignment of Proceeding

Michel Peter Florio is the assigned Commissioner and Kelly A. Hymes is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. R.14-08-013 and R.14-10-003 will address the valuation and integration of distributed energy resources.
2. R.12-06-013 and R.15-12-012 will work together to address time of use rate issues.
3. It is efficient to address time of use rates in R.12-06-013 and R.15-12-012.
4. R.16-12-017 is the Commission's primary venue to implement SB 350.
5. The issuance of a ruling incorporating the Staff Proposal, asking questions regarding the Staff Proposal, and allowing comment on the Staff Proposal is a proper notice and comment methodology to create a record in this proceeding for this decision.
6. Parties were provided an additional opportunity to discuss the Staff Proposal during the January 13, 2016 workshop.
7. D.14-12-024 confirmed that fossil-fueled back-up generation is antithetical to the efforts of the Commission's Energy Action Plan and the Loading Order.
8. The Energy Action Plan and the Loading Order indicate a preference for cleaner technologies.
9. No party provided any objection to the statutory directives from Assembly Bill 57 and Senate Bill 1414.
10. The Commission's adopted policy statement that "fossil-fueled back-up generation is antithetical to the efforts of the Commission's Energy Action Plan and the Loading Order" essentially has no effect without any associated conditions or requirements.

11. Not having a clearly identified prohibition on the use of certain resources in demand response conflicts with our adopted policy statement and may prevent the Commission from meeting its aggressive clean policy goals.

12. D.14-12-024 is the second time that the Commission has requested the Utilities to collect data and the second time that the Commission has received more questions from the Utilities than the actual data.

13. The Commission initially asked the Utilities in 2011 to collect the data on backup generation use.

14. A decision in 2016 to abandon the data collection is not a hasty action.

15. The purpose of the data collection was to determine the number of customers using back-up generation.

16. The purpose of the demand response potential study is to assist the Commission in setting a goal (for demand response) based on potential, needs, and value.

17. The purposes of the data collection and the Study do not intersect.

18. It is reasonable to dismiss the claim by PG&E that the demand response potential study will help inform the back-up generation issue.

19. The Staff Proposal claims that the Utilities have implied that costs would be in the millions of dollars due to a reliance on consultants and surveys to extract data; no party provided any debate to the contrary.

20. Questions remain regarding the costs of data collection.

21. The purpose of the data collection required by D.14-12-024 was to ascertain whether the implementation of a prohibition on back-up generation would negatively impact the amount of demand response the programs would continue to curtail.

22. The data collection may not provide an adequate answer to our question.

23. A deadline of January 1, 2018 to begin the prohibition of the defined resources in demand response provides ample time for implementation.

24. The list of prohibited resources results from an understanding that demand response is an actual reduction in demand, not supported by a fossil-fueled resource.

25. The lack of a prohibition of the use of fossil-fueled resources conflicts with the Commission's clean energy policies.

26. The Commission previously determined that bottoming cycle CHP and pressure reduction turbines are considered renewable resources.

27. Energy storage is considered to be a strategic resource to meet AB 2514 requirements.

28. The intent of AB 2514 confirms that the Commission is required to expand the use of energy storage systems to minimize greenhouse gas emissions.

29. It is reasonable to ensure that the adopted list of prohibited resources do not conflict with statutory requirements of AB 2514.

30. The parties' concern that the multi-step process could discourage customer participation is valid.

31. Public Utilities Code Section 453 requires the Commission to ensure that no public utility shall establish unreasonable differences in rates, charges, service, facilities, or in any other respect, between classes of service.

32. Residential customers are unlikely to have an additional source to power their air conditioner.

33. It is reasonable to require less strict requirements from a class of customers where the requirements are unlikely to be applicable.

34. The Staff Proposal, as revised, does not violate Public Utilities Code Section 453.

35. It is appropriate and less burdensome to require a separate prohibition provision in the demand response program tariffs rather than a two-step attestation process.

36. The commission has previously approved the use of electronic signatures in third party direct participation demand response programs.

37. It is reasonable to approve the use of electronic signatures for the purposes of attestation in the demand response prohibition enforcement program.

38. Requiring bi-annual site visits for every residential and non-residential customer to verify customer compliance with the demand response prohibition provision would be cost prohibitive.

39. Prudence requires some measure of verification of customer compliance with the prohibition provision.

40. A selective audit program may provide the balance of verification without the costliness of annual site visits during a demand response event.

41. A review of 2018 demand response program applications for current demand response programs should be routine.

42. It is unknown what the second phase of the demand response potential study will present to the Commission.

43. It is unknown what the new advanced demand response programs will entail, including the implementation time and potential need for increased ratepayer funds.

44. It is unknown whether the CAISO market will be ready to integrate the newer model demand response programs.

45. The newer model demand response programs anticipated as a result of the second phase of the demand response potential study may produce a longer than normal review process.

46. A review of the current demand response programs is very different from a review of new advanced demand response programs.

47. Reviewing both the current and the new advanced demand response programs concurrently may result in a delay of approval for the current programs.

48. It is reasonable to review the current demand response programs separately from the new advanced demand response programs.

49. Parties were generally in agreement regarding the need for one goal for both load modifying and supply side demand response resources.

50. Parties recognized that demand response should reliably and efficiently meet the needs of the grid.

51. Many parties indicated a need for demand response to be cost-effective.

52. R.14-08-013 and R.14-10-003 will provide a methodology and a framework to enable the Commission to value distributed energy resources on a level playing field and provide a platform for competitively procuring the resources on an integrated basis.

53. Once the Commission adopts the methodology and framework developed in R.14-08-013 and R.14-10-003, the goal and set of principles adopted in this proceeding will work side-by-side.

54. Parties generally agreed that the issues of system reliability, environmental needs and customer needs are the top attributes of demand response.

55. Promoting market-driven demand response solutions is fundamental to growing reliable demand response.

56. The Utilities' demand response programs and third-party provider demand response programs should be on a level playing field.

57. The playing field is uneven on several levels and until we can guarantee a balanced market, we will allow certain carve outs within reason.

58. There has not been sufficient time to ascertain the success of the energy efficiency ten-year rolling portfolio.

59. The demand response programs have gone and continue to go through multiple changes.

60. It is prudent to adopt a five-year cycle with a mid-cycle review in 2020.

61. The demand response auctions have received a great amount of interest by third parties.

62. The Commission cannot conclude solely on the basis of the success of the auctions that the demand response auction mechanism framework is a successful.

63. The Utilities were the natural administrators of demand response with significant experience in marketing, outreach, and rate design.

64. The roles and responsibilities for Utilities and third-party providers have changed significantly over the years.

65. The Commission has expanded the choice of demand response services, programs, and providers.

66. There is an increased level of interest by customers participating in these choices.

67. The expanded choices and increased levels of interest are new.

68. Statistics measuring the success of the various new efforts will begin to materialize.

69. It is premature to dismantle the current demand response provider model where the utilities play the key administrative role.

70. The experience of the Utilities in demand response should not be ignored.

71. Ratepayers invested a great deal of time and money in order for the Utilities to gain their experience in demand response.

72. The principle of consumer choice dovetails with the principle of competition.

73. It is reasonable to continue both roles of the Utilities, as demand response program providers and administrator.

74. There is strong support for transitioning the demand response auction mechanism from pilot status.

75. To move from pilot status, the demand response auction mechanism must be deemed successful.

76. In considering whether to move the demand response auction mechanism from pilot status, we should review whether the pilot met the objectives of the feasibility of procuring resources for resource adequacy by third parties in the CAISO market and whether the winning bidders effectively integrated their resources into the market.

77. Measuring the level of third party and customer engagement, including customer performance, and the level of competition are the most important aspects to meet the objectives of the demand response auction mechanism pilot and determine whether to transition from pilot to program status.

78. There is insufficient information to conclude whether the auction mechanism would be more successful under the administration of a third-party.

79. The previous demand response auctions have been administered under the Commission's direction, guidance and oversight.

80. It is reasonable to continue the role of the Utilities as administrators of the demand response auction mechanism, upon Commission approval to transition to program status.

81. The Utilities supply side demand response programs are currently required to be bid into the CAISO market.

82. It is reasonable to require that demand response programs administered by the Utilities shall not participate in the auction mechanism.

83. Creating separation of the two utility roles (as program providers and auction administrators) while allowing the continuation of both sets of programs meets with our principles of competition and customer choice.

84. A demand response auction mechanism program should offer providers and customers as much flexibility as is possible and decrease the risk involved.

85. It is reasonable to allow providers to offer contracts for the demand response auction from one to five years, but within the budget cycle time.

86. An obligation to replace resource adequacy capacity not delivered ensures protection for the procuring load serving entity and ratepayers.

87. Potential penalties in the demand response auction mechanism ensure the ratepayers are not financially liable if the contracted capacity is not delivered.

88. There is a need to allow the residential sector to grow and learned from the competitive environment of the auction mechanism before we eliminate the set-aside for residential customers.

89. The size of the auction mechanism should be flexible based on the competitiveness of the bids received.

90. The obligation to accept all complying bids up to the simple average August capacity bid price should ensure that the auction mechanism provides substantial growth opportunity for performance based demand response.

91. Limiting procurement to the simple average August bid price should encourage competitive bidding behavior.

92. Adoption of a one gigawatt ceiling and the known price benchmark should protect ratepayers.

93. Recording contract and administration expenses from the auction mechanism into the relevant energy resource recovery account will enable the Utilities to procure on an annual basis and allow one to five-year contract without the barrier of a five-year budget cycle.

94. No party opposed the use of the RECAP methodology as the interim A Factor.

95. No party opposed the recommendations of the Permanent Load Shifting Cost Effectiveness Working Group.

96. The majority of demand response supply side programs will be bid into the CAISO market beginning in 2017 with the remaining programs required to be integrated into the market by January 1, 2018.

97. The CAISO market price will determine whether a demand response resource bid into the market will be dispatched.

98. The weekly demand response exception reporting is no longer necessary.

99. Issues regarding hard triggers are now irrelevant given the Commission's November 19, 2015 decision not to adopt any hard trigger proposals.

100. The Commission and the CAISO have processes in place for vetting and deciding demand response integration issues.

101. We find that it is duplicative, and therefore unreasonable, to continue the work of the Integration and Operations Working Groups.

Conclusions of Law

1. Guidance provided in this decision may require additional refined depending upon future decisions in R.16-02-007, R.15-12-012, R. 14-10-003, R.14-08-013, and R.12-06-013.

2. Adequate notice and opportunity to be heard has been provided by the September Ruling presenting a Staff Proposal recommending the prohibition of the use of certain resources during demand response program events.

3. Public Utilities Code Section 380.5 requires the Commission "to establish rules consistent with state and federal law for how and when back-up generation may be used within the demand response program."

4. Section 380.5 makes clear that efforts to incorporate demand response into the state's resource adequacy program should also reduce greenhouse gas emissions.

5. The Commission should adopt a clearly identified prohibition on the use of certain resources in order to enforce its policy statement regarding these resources.

6. The Commission should modify D.14-12-024 to abandon the data collection effort and to establish a date to begin the prohibition of the use of certain resources during demand response program events.

7. The Commission should adopt a date of January 1, 2018 to begin the prohibition of the resources defined in this decision.

8. CHP facilities should be included in the list of prohibited resources.

9. It is reasonable to exclude bottoming cycle CHP and pressure reduction turbines from the list of prohibited resources used during demand response events, in return for an incentive.

10. The Commission should exclude energy storage from the list of prohibited resources.

11. It is reasonable to eliminate the requirement of a residential customer attestation in the prohibition enforcement program.

12. The Commission should adopt the use of tariffs to enforce the prohibition of the listed resources in demand response.

13. The Commission should require non-residential customers to electronically attest to whether they own a prohibited resource and a) agree not to use the prohibited resource to reduce load during a demand response event in return for an incentive or b) if the prohibited resource is required to be used for safety reasons, agree to a default adjustment.

14. It is reasonable to require some level of verification of customer compliance with the demand response resource prohibition requirement.

15. The Commission should not delay a review of the current demand response programs.

16. The Commission should review the current demand response programs separately from the new advanced demand response programs.

17. The Commission should determine the issue of integrating demand response with other resources in rulemakings 14-08-013 and 14-10-003.

18. The Commission should translate the major attributes of demand response into a set of principles by which demand response programs should abide.

19. The Commission should adopt a five-year cycle with a mid-cycle review in 2020.

20. The Commission should not adopt CAISO's recommendation to transition solely to competitive solicitations.

21. The Commission should allow customers to determine the eventual role the Utilities will play in the future, through selections from the various demand response options that are provided.

22. The Commission should adopt the following measurements for determining the success of the demand response auction mechanism: 1) Were

new, viable third-party providers engaged; 2) Were new customers engaged: 3) Were bid prices competitive; 4) Were offer prices competitive in the wholesale markets; and 5) Were resources reliable when dispatched.

23. The Commission should separate the two roles of the Utilities, as providers of demand response programs and as administrators of the demand response auction mechanism.

24. The Commission should prohibit the Utilities from bidding their demand response programs in the demand response auction mechanism.

25. The Commission should adopt the RECAP methodology as the interim A Factor.

26. The Commission should adopt the recommendations of the Permanent Load Shifting Cost Effectiveness Working Group.

27. The Commission should relieve the Utilities of the requirement to provide weekly demand response dispatch exception reports.

28. The Commission should not grant the petition to continue the work of the Integration and Operations Working Groups.

O R D E R

IT IS ORDERED that:

1. Ordering Paragraph 11 of Decision 14-12-024 is modified as follows:

   Certain fossil-fueled resources should not be allowed as part of a demand response program, beginning January 1, 2018, subject to the rules adopted in a future implementation program to include definitions and enforcement and verification mechanisms.

2. Ordering Paragraphs 12, 13, 14, and 15 of Decision 14-12-024 are deleted.

3. Beginning on January 1, 2018, the following list of resources are prohibited to be used for load reduction during demand response events: distributed

generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in topping cycle Combined Heat and Power (CHP) or non-CHP configuration. The following resources are exempt from the prohibition: pressure reduction turbines and waste-heat-to-power bottoming cycle CHP, as well as storage and storage coupled with renewable generation that meet the relevant greenhouse gas emissions standards adopted for the Self Generation Incentive Program. The following programs are exempt from the prohibition: air conditioner cycling programs, permanent load shifting programs, schedule load reduction programs, the optional binding mandatory curtailment, time of use rates, critical peak pricing, real time pricing, and peak time rebate.

4. All demand response providers including Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities), as well as third-party demand response providers shall enforce the prohibition of the resources listed in Ordering Paragraph 3 in the following manner:

   a. For all residential demand response programs: A new and separate provision shall be included in the tariff or contract for each program explaining the prohibition and requiring a residential customer to agree not to use a prohibited resource to reduce load during a demand response event. For returning customers, all demand response providers shall provide notice to the customers of the new provision.

   b. For all non-residential demand response programs: A new and separate provision shall be included in the tariff or contract language for each program explaining the prohibition and requiring a non-residential customer to i) agree not to use a prohibited resource to reduce load during a demand response event or ii) in cases where the customer is required to use the prohibited resource for safety reasons, agree to a default adjustment. For new non-residential customers, the attestation shall occur at the time of enrollment and shall be provided with an electronic signature. For returning non-residential customers, the demand response providers shall provide notice to the customers of the new provision and outreach to the customers that a signature, which may be an electronic signature, agreeing to the prohibition or the default adjustment shall be provided no later than December 31, 2017.

c. No later than 90 days after the issuance of this decision, the Utilities shall file a tier three advice letter proposing draft language for the new prohibition tariff provision for review and approval by the Commission. The Utilities shall also include proposals for fund shifting in the 2017 demand response budgets to cover the costs of implementing the prohibition.

5. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the Utilities) shall immediately hire expert consultants to assess whether it is possible, and if so by what methods and data sources, to evaluate whether non-residential customers are complying with the demand response prohibition requirement. The Utilities are instructed to comply with the following instructions:

a. The Utilities are permitted to utilize existing evaluation, measurement and validation funds approved in Decision 16-06-029 to cover the costs of the consultants, allocated in the following percentages: 40 percent for both PG&E and SCE, and 20 percent for SDG&E.

b. The Utilities shall require the consultants to provide recommendations on how best to design an audit verification plan.

c. All meetings with the consultants shall include a representative of the Commission's Energy Division, at Energy Division's discretion.

d. The Utilities shall serve the consultant's report on its findings to the service list no later than April 1, 2017.

e. The Utilities shall host a workshop on the audit verification plan report. Notice of the workshop shall be provided to all parties including representatives of the Commission's Energy Division.

f. No later than July 1, 2017, the Utilities shall file a Tier Three Advice Letter requesting approval of a final proposed audit verification plan, incorporating feedback received during the workshop. The verification plan shall be effective January 1, 2018.

6. No later than January 16, 2017, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall each file an application requesting approval and funding for 2018 demand response portfolios for existing models of demand response programs and activities pursuant to the guidance provided in this decision.

7. The following goal for Commission-regulated demand response programs is adopted:

> *Commission regulated demand response programs shall assist the State in meeting its environmental objectives, cost-effectively meet the needs of the grid, and enable customers to meet their energy needs at a reduced cost.*

8. The following set of principles for all Commission-regulated demand response programs are adopted and shall be adhered to by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and third-party providers:

- *Demand response shall be flexible and reliable to support renewable integration and emission reductions;*
- *Demand response shall evolve to complement the continuous changing needs of the grid;*
- *Demand response customers shall have the right to provide demand response through a service provider of their choice and Utilities shall support their choice by eliminating barriers to data access;*

- *Demand response shall be implemented in coordination with rate design;*
- *Demand response processes shall be transparent; and*
- *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 through performance-based contracts at competitively determined prices, and dispatched pursuant to wholesale or distribution market instructions, superseded only for emergency grid conditions.*

9. Beginning with the 2018 application for current demand response programs, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) shall file applications on a five-year cycle with a mid-cycle review. The 2018 demand response application shall be for program years 2018 through and including 2022. A mid-cycle review shall occur in 2020 for the two final years of the program cycle. The Utilities shall file a mid-cycle review tier-three advice letter no later than April 1, 2020 providing an update on each of their demand response programs and requesting approval of any necessary changes.

10. The Commission's Energy Division is authorized to conduct an independent analysis of the results of the 2016 and 2017 demand response auction mechanism pilot auctions and the subsequent deliveries, emphasizing the following five criterion: a) Were new, viable third-party providers engaged; b) Were new customers engaged; c) Were bid prices competitive; d) Were offer prices competitive in the wholesale markets; e) Did demand response providers aggregate the capacity they contracted, or replace it with demand response from another source in a timely manner; and f) Were resources reliable when dispatched.

Energy Division is authorized to hold a workshop no later than January 31, 2017 to present the metrics and evaluation plan it will use for the assessment of the criteria. Parties shall be provided an opportunity to comment on the metrics and evaluation plan. No later than April 1, 2017, the Energy Division should provide a public report on its final list of metrics and evaluation plan. A draft resolution, presenting a final analysis and recommendation will be issued by the Energy Division no later than June 1, 2018.

If the Commission approves the resolution, Energy Division will hold a workshop within 30 days of the approval. The purpose of the workshop will be to confirm the steps to implement the demand response auction mechanism post pilot.

11. The Commission's Energy Division is authorized to access demand response research fund, approved by the Commission in D.12-04-045 and D.16-09-029, if consulting expertise is necessary for the analysis of the demand response auction mechanism pilot.

12. Following the Commission approval to transition from pilot status, the demand response auction mechanism shall continue to be administered by Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) (jointly, the Utilities) and be the main procurement mechanism for resource adequacy capacity from all third-party demand response providers. Demand response programs implemented by the Utilities shall not participate in the auction mechanism and shall be capped at 2017 annual budget levels until the mid-cycle program review. The Utilities shall adhere to the following parameters:

a. The Utilities shall offer annual auctions and must offer contracts to all complying bids up to the simple average August capacity bidding price.

b. The Utilities are not obligated to procure over 400 megawatts each for PG&E or SCE, or 200 megawatts for SDG&E.

c. The Utilities are not obligated to accept bids priced above the long term avoided cost of generation at the time of the auction.

d. The Utilities are not obligated to award contracts to bids in which non-August capacity prices are outliers.

e. The Utilities shall allow a range of contract lengths for the winning bidders from one to five years.

f. The penalty structure shall be equivalent to those provided in the resource adequacy contracts.

g. The Utilities are authorized to record contract and administration expenses from the administration of the demand response auction mechanism in the relevant Energy Resource Recovery Account.

h. The Utilities shall ensure adherence to the prohibition of certain resources used in demand response.

13. If approved by the Commission, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company(jointly, the Utilities) shall file a tier one advice letter requesting approval of the demand response auction mechanism, as described herein. The Utilities shall file the tier one advice letter no later than 60 days following the workshop directed above in Ordering Paragraph 11.

14. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company(jointly, the Utilities) shall ensure their applications for 2018-2022 demand response portfolios utilize the Commission-adopted 2015 demand response protocol for calculating the cost-effectiveness of each program and use the Renewable Electricity Capacity Planning methodology as the interim methodology for the A Factor.

15. The recommendations of the Permanent Load Shifting Cost-Effectiveness Working Group, as indicated in Table 1 of this decision, are hereby adopted.

16. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California are relieved of the requirement to provide the weekly dispatch exception reports beginning on January 1, 2017.

17. Phase Two of Rulemaking 13-09-011 remains open to address the implementation of the cost causation principles. Phase Three remains open to address the second phase of the Demand Response Potential Study.

This order is effective today.

Dated September 29, 2016, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
LIANE M. RANDOLPH
Commissioners

Carla J. Peterman, being necessarily absent, did not participate.