Decision 17-10-017 October 26, 2017

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

DECISION ADOPTING STEPS FOR IMPLEMENTING THE COMPETITIVE NEUTRALITY COST CAUSATION PRINCIPLE, REQUIRING AN AUCTION IN 2018 FOR THE DEMAND RESPONSE AUCTION MECHANISM, AND ESTABLISHING A WORKING GROUP FOR THE CREATION OF NEW MODELS OF DEMAND RESPONSE

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Summary

This Decision adopts steps to implement the Competitive Neutrality Cost Causation Principle, which allow Community Choice Aggregation or Direct Access electric service providers to create and administer demand response programs on a level playing field with investor-owned utilities. These steps are designed to ensure the objectives of the demand response goal and principles are met. In addition, this Decision orders a 2018 auction for 2019 deliveries for the Demand Response Auction Mechanism pilot. Moreover, to combat barriers to market integration and develop a framework for new models of demand response, this Decision establishes two working groups open to all interested persons: Supply Side Working Group and Load Shift Working Group. The investor-owned utilities, on behalf of both working groups, shall provide quarterly status reports on the working groups' progress and, on behalf of the Load Shift Working Group, a final report on its proposals, which will inform a future rulemaking to consider new models of demand response.

This Decision completes phases two and three of this proceeding and determines that phase four should be a new and separate proceeding in the future. Rulemaking 13-09-011 remains open to address a pending application for rehearing.

1. Procedural Background

On September 19, 2013, the Commission initiated Rulemaking (R.) 13-09-011 by approving the Order Instituting Rulemaking (OIR) to enhance the role of demand response in meeting the State's electric resource planning needs and operational requirements. The Commission initiated the rulemaking with the intention of retooling demand response to align with the grid's needs while enhancing the role of demand response in carrying out California's energy policies.[1]

The first major decision of this proceeding occurred in December 2014 when the Commission approved Decision (D.) 14-12-024, requiring bifurcation of demand response programs and integration of supply side resources into the California Independent System Operators (CAISO) energy market by the year 2018. Relevant to this Decision, D.14-12-024: 1) adopted a competitive neutrality cost causation principle, 2) directed Commission staff to study the potential of demand response in California (Potential Study), and 3) established a working group to develop the Demand Response Auction Mechanism Pilot (Pilot).[2]

On April 1, 2016, Lawrence Berkeley National Laboratory (Contractors) delivered its interim report on Phase I results of the Potential Study.[3] The interim results focused on existing programs and stated that the second phase of the Potential Study would focus on newer models of demand response. In D.16-09-056, the Commission established guidance to Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE), (jointly, the Utilities) regarding existing models of demand response programs for 2018 and beyond and determined that

[1] OIR at 15.

[2] D.14-12-024 at 18.

[3] 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

a second decision would focus on new models of demand response programs, which would be developed following the delivery of the second phase of the Potential Study. The Contractors provided the second phase of the Potential Study on March 1, 2017.

One objective of the Potential Study was to assist the Commission in setting a goal for demand response. In September 2016, the Commission approved D.16-09-056, which adopted guidance for future demand response portfolios by establishing a goal and a set of principles for demand response. Also relevant to this Decision, D.16-09-056 determined that certain fossil-fueled resources should not be allowed as part of a demand response program, beginning January 1, 2018.[4]

In early 2017, the Commission facilitated three workshops in this proceeding related to this Decision. On February 22, 2017, a workshop to discuss program year 2016 took place, during which time parties addressed remaining barriers to the integration of demand response into the CAISO energy market. The assigned Administrative Law Judges (ALJs) also facilitated a workshop on April 4, 2017, to discuss the pathway toward development of new models of demand response. Lastly, on April 10, 2017, parties participated in a workshop

[4] D.16-09-056 at Ordering Paragraph 3 established the following list of resources prohibited to be used for load reduction during demand response events: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied 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 water-heat-to-power bottoming cycle CHP, storage, and storage coupled with renewable generation that meet the relevant greenhouse gas emissions standards. 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.

to discuss the implementation of the cost causation competitive neutrality principle and review the February 17, 2017 proposal for such implementation filed by the Utilities (Utilities Proposal).[5]

On April 27, 2017, the Commission approved D.17-04-045, Addressing Petitions for Modification. Relevant to this Decision, D.17-04-045 determined that business opportunities for demand response providers could be limited under the previously approved $27 million budget for the 2017 Pilot solicitation and directed responses to questions regarding whether the Commission should approve an additional auction in 2018 for 2019 deliveries.[6]

The assigned Commissioner issued an Amended Scoping Memo on May 11, 2017, which formally expanded the scope of the proceeding to include new models of demand response. The May 11, 2017 Amended Scoping Memo extended the schedule of the proceeding not only to address this new issue but also to complete outstanding issues from phases two and three, including addressing the proposal to implement the cost causation competitive neutrality principle and whether to authorize an additional auction in 2018 for the Pilot.

On May 22, 2017, the assigned Administrative Law Judges issued a Ruling requesting responses to three sets of questions: 1) Implementation of the Competitive Neutrality Cost Causation principle; 2) CAISO Market Integration Barriers; and 3) Pathways to New Models of Demand Response.

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[5] The following parties filed comments on the Utilities' Implementation Proposal on March 3, 2017: EnerNoc, Inc., Comverge, Inc., CPower, and EnergyHub (together the Joint Demand Response Parties); Marin Clean Energy; Office of Ratepayer Advocates (ORA); and Shell Energy North America (Shell). Reply Comments were filed on March 15, 2017 by the California Large Energy Consumers Association (CLECA), Alliance for Retail Energy Markets/Direct Access Customer Coalition, Marin Clean Energy, and the Utilities.

[6] D.17-04-045 at Ordering Paragraph 6.

On June 19, 2017, the following parties timely filed comments to the questions regarding the implementation of the competitive neutrality cost causation principle: CLECA; Marin Clean Energy; ORA; OhmConnect, Inc. (OhmConnect); and the Utilities. On July 5, 2016, Marin Clean Energy, ORA, and the Utilities timely filed reply comments.

On July 6, 2017, the following parties timely filed responses to the questions regarding CAISO Market Integration Barriers and Pathways to New Models of Demand Response: California Energy Storage Association (CESA), CAISO, CALSEIA, CLECA, Joint Demand Response Parties, NRG Energy, Inc., ORA, OhmConnect, PG&E, SDG&E, Stem, Inc., SCE, and Tesla. On July 17, 2017, the following parties timely filed reply comments: CLECA, Joint Demand Response Parties, PG&E, SCE, and Tesla.

Also on July 6, 2017, the following parties timely filed responses to the questions posed in D.17-04-045 regarding a possible 2018 auction in the Pilot: Joint Demand Response Parties, ORA, OhmConnect, PG&E, SDG&E, and SCE. On July 17, 2017, the following parties timely filed reply comments: Joint Demand Response Parties, ORA, PG&E, SDG&E, and SCE.

2. Discussion

There are three issues addressed in this Decision: 1) How to implement the competitive neutrality cost causation principle adopted by the Commission in D.14-12-024; 2) Whether the Commission should approve an additional Pilot auction to be held in the spring of 2018 for contracts for delivery in 2019; and 3) Guidance for the appropriate next steps for developing the new models of demand response discussed in the Potential Study. Each issue is discussed and determined separately below.

2.1. Competitive Neutrality Cost Causation Principle

This Decision adopts a simplified version of the Utilities proposal for implementing the Competitive Neutrality Cost Causation Principle adopted in D.14-12-024. First, this Decision adopts a definition for what constitutes a similar program:

A Community Choice Aggregator or Direct Access Provider's (Competing Provider) demand response program is considered similar to a demand response program provided by an investor-owned utility if the Competing Provider's program meets all of the following requirements:

- is offered to the same type of customer (e.g., residential customer) and approximate number of Competing Provider's customers to which the Competing Utility offers its demand response program;
- is classified as and can be demonstrated to be the same resource as the Competing Utility's demand response program, either a load modifying or supply resource, as defined by the Commission;
- can validate that its demand response program customers are not receiving load shedding incentives for the use of prohibited resources during demand response events; and
- allows the participation of third-party demand response providers or aggregators, if the Competing Utility's demand response program also allows such third-party participation.

Second, this Decision adopts a four-step process using a Tier Three Advice Letter regulatory process to determine whether a demand response program is similar. If the Commission determines through the Tier Three Advice Letter process that a Competing Provider's demand response program is similar to a Competing Utility's program, the Competing Utility shall begin the process of ceasing all targeted marketing and cost recovery of the similar program within

30 days of the issuance of the Resolution making the determination and shall complete the process within 365 days of the issuance of that Resolution. In order to end cost recovery from the Competing Provider's customers for the Competing Utility's similar demand response programs, the Competing Utility shall employ the use of a credit on the Competing Provider's customers' bill.

Furthermore, this Decision determines that in order to make certain the Commission is fulfilling its responsibility to ensure safe and reliable electric service, a report of the implementation of the Competitive Neutrality Cost Causation Principle should be completed within three years after the first Competing Provider receives an approval from the Commission for a similar demand response program. The report should include a review of the implementation steps, the regulatory approval process, and the impact of the implementation, as further described below.

2.1.1. Competitive Neutrality Cost Causation Principle Background

In D.14-12-024, the Commission adopted two cost causation principles. First, D.14-12-024 held that any demand response program or tariff that is available to all customers shall be paid for by all customers. Hence, if a demand response program or tariff is only available to bundled customers, the costs for that program or tariff would only be borne by bundled customers. Second, the Commission pointed to a competitive barrier, as explained by Marin Clean Energy, where Community Choice Aggregator or Direct Access providers "cannot justify creating such programs at ratepayer expense when Community Choice Aggregator customers are already being charged for the utility-offered programs."[7] In order to combat this barrier, the Commission adopted the competitive neutrality cost causation principle whereby a competing utility shall cease cost recovery from and targeted marketing to a Community Choice Aggregator or Direct Access provider's customers when that provider implements a similar demand response program in the utility's service territory.[8]

Pursuant to a December 2, 2016 Ruling, on February 17, 2017 the Utilities filed a proposal for implementing the Competitive Neutrality Cost Causation Principle (Proposal). The Proposal is a multi-step process that would, first, have a Direct Access or Community Choice Aggregator provider offer interested persons notice of an intention to launch a demand response program in a competing utility's territory. The notice would include information on how the proposed demand response program: (1) meets current Commission demand response policy and state mandates, and (2) complies with the definition of being similar to a current demand response program in the competing utility's territory. The Proposal suggests that interested persons be permitted to comment on the contents of the notice. The Commission would then proceed with the Proposal's step two, an informal assessment of whether the proposed program meets State policy and Commission mandates. If the proposed demand response program meets the requirements, the Commission would then proceed with the Proposal's step three, a formal assessment of whether that program is similar to an existing program; this assessment would take place through a workshop and a formal Commission determination.

[7] D.14-12-024 at 48-49.

[8] D.14-12-024 at Ordering Paragraph 8b.

The Utilities propose that the determination of a similar program should include whether the provider/program: i) has sufficient financial backing to achieve Commission demand response goals, ii) allows the use of third-party providers and aggregators, iii) prohibits fossil-fueled resources for demand response purposes and has established the required verification procedures; and iv) is bifurcated into supply-side and load modifying resources. If the proposed program meets the standards, the competing utility would proceed with the Proposal's step four: removing the direct access or Community Choice Aggregator provider's customers from the affected utility demand response program along with exempting those customers from paying the utility program costs. The Proposal states that the "timing to complete implementation of these changes should be approximately one year from issuance of the Commission's determination, with some flexibility, for instance, for coordination with utility rate mechanisms, as needed."[9] Finally, the Proposal recommends the use of a credit on the Competing Provider's customers' bill to end cost recovery of the Competing Utility's similar demand response program(s).

Comments on the Utilities' Proposal range from support by ORA to the request for additional information and clarity by the Joint Demand Response Parties. Both Marin Clean Energy and Shell Energy North America (Shell) contend that the Proposal does not address the essence of the Principle's intention to avoid barriers to competition in the demand response market, is

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[9] Joint Utilities' Proposal on Competitive Neutrality Cost Causation Principle, February 17, 2017, at 6.

"complex and administratively burdensome," and should be simplified.[10] Parties disagree upon the definition of a "similar program."[11] Parties also express concern about the following matters, in no particular order:

- whether a determination of the permanent Demand Response Auction Mechanism as being a "similar program" could result in a "bundled-only program;"[12]
- whether the implementation time is reasonable;[13]
- whether the use of third-party providers should be required in the proposed similar demand response programs;[14]
- whether the Commission would be overreaching its authority in implementing portions of the Utilities' Proposal;[15]
- whether the recovery of stranded costs[16] are in the scope of this proceeding;[17] and

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10 Shell Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 2 and Marin Clean Energy Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 1-3.

11 *See*, for example, Marin Clean Energy Opening Comments to the Utilities' Implementation Proposal, March3, 2017 at 5-6; Shell Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 3-6; and Joint Demand Response Parties Comments to the Utilities' Proposal, March 3, 2017 at 3-5.

12 Joint Demand Response Parties Comments to the Utilities' Proposal, March 3, 2017 at 5.

13 Shell Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 4-5.

14 Shell Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 5.

15 Marin Clean Energy Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 4 and Shell Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 5.

16 The Utilities state that there are probably no authorized existing costs that would likely be stranded in the next few years expect possibly for the SCE contracts to procure preferred resources to meet local capacity needs in the Western Los Angeles Basin. (*See* Utilities' Proposal at 23 and 26-27.)

- whether the Utilities' proposed methodology for discontinuing cost recovery is reasonable.[18]

During the April 10, 2017 workshop, the parties discussed several aspects of the Utilities' Proposal and focused on the definition of similar program. While the parties participated in small group discussions and developed definitions, there was no overall consensus on how to define a similar program. In response to the workshop, a Ruling was issued on May 22, 2017 asking parties to respond to questions regarding this matter. Parties were once again asked to define a similar demand response program. Commenters agree that similar does not mean identical, but opinions regarding the degree to which two programs can be considered similar are varied. Parties were also asked what regulatory process should be followed to determine whether a demand response program is similar. Most parties propose the Advice Letter process with some variation of Tier Two and Tier Three, while CLECA proposed an expedited application process.

2.1.2. Competitive Neutrality Cost Causation Principle Jurisdictional Issues

The Competitive Neutrality Cost Causation Principle relates to two different types of load serving entities with different regulatory requirements than the Utilities. Each is explained below along with an overview of the Commission's jurisdiction as it relates to demand response programs.

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17 Marin Clean Energy Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 6 and Shell Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 7.

18 Marin Clean Energy Opening Comments to the Utilities' Implementation Proposal, March3, 2017 at 8 and Shell Opening Comments to the Utilities' Implementation Proposal, March 3, 2017 at 4-5.

Assembly Bill (AB) 117 and Senate Bill (SB) 790 established Community Choice Aggregation and authorized local governments to aggregate customer electric load and purchase electricity for customers. AB 117 requires electrical corporations to cooperate fully with any Community Choice Aggregators that implement Community Choice Aggregator programs. The investor-owned utility remains responsible for providing transmission and distribution services, metering billing collection and customer service to retail customers that participate in a Community Choice Aggregator program.[19]

In some respects, the Commission's regulatory authority over Community Choice Aggregators differs from its jurisdiction over the investor-owned utilities. Nonetheless, Community Choice Aggregators must comply with resource adequacy obligations. Specifically, Pub. Util. Code § 380 directs the Commission to establish resource adequacy requirements for all load serving entities and requires that each load serving entity is subject to the same requirements for resource adequacy and the renewables portfolio standard program that are applicable to electrical corporations.[20] Community Choice Aggregators are included in the definition of load serving entity. Furthermore, the Commission requires sufficient information, including, but not limited to anticipated load, actual load, and measures taken to ensure resource adequacy, to be reported to enable the Commission to determine compliance with resource adequacy

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19 Pub. Util. Code § 366.2.

20 Pub. Util. Code § 380(e).

requirements.[21] Determination of the full extent of the Commission's jurisdiction over Community Choice Aggregators is not within the scope of this proceeding.[22]

Direct Access service is retail electric service where customers purchase electricity from a competitive provider called an electric service provider, instead of from an investor-owned utility. The investor-owned utility delivers the electricity from the electric service provider to the customer over the utility's distribution system. SB 695 requires the Commission to ensure that these other electric service providers are subject to the same procurement–related requirements that apply to investor-owned utilities, including resource adequacy requirements, renewables portfolio standards, and greenhouse gas emission reductions.

As indicated above, Pub. Util. Code § 380 requires that all load serving entities (including electrical corporations, electric service providers, and Community Choice Aggregators) shall be subject to the same requirements for resource adequacy and the renewables portfolio standard program that are applicable to electrical corporations,[23] and are required to provide sufficient information to enable the Commission to determine the required compliance.[24]

2.1.3. Implementation of the Competitive Neutrality Cost Causation Principle

In implementing the Competitive Neutrality Cost Causation Principle, the Commission is faced with the need to balance competing objectives. While the

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[21] Pub. Util. Code § 380(f).

[22] The Commission has issued decisions on the question in various decisions, including D.10-12-035 and D.05-12-042 (as modified by D.10-05-050).

[23] Pub. Util. Code § 380(e).

[24] Pub. Util. Code § 380(f).

underlying objective of this principle is ensuring fair competition between the Utilities' demand response programs and those provided by Community Choice Aggregator and Direct Access providers (Competing Providers), the Commission must also ensure that it is meeting the adopted demand response goal whereby Commission regulated demand response programs 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.[25] In balancing the objective of competitive fairness with the objectives established in the demand response goal and principles,[26] this Decision establishes the following four-step process for implementing the Competitive Neutrality Cost Causation Principle.

- Step One: A Competing Provider may file a Tier Three Advice Letter requesting Commission determination that the Competing Provider's proposed demand response program is similar to a Competing Utility's program.

The Utilities' Proposal recommends a preliminary assessment of whether a proposed competing program supports state policy and Commission mandates followed by a more thorough detailed assessment of program attributes through evidentiary hearings, workshops, etc.[27] Marin Clean Energy contends the multiple-step process is onerous and anti-competitive. This Decision balances

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[25] D.16-09-056 at Ordering Paragraph 7.

[26] D.16-09-056 established six principles for all Commission-regulated demand response programs and required that the Utilities and third party providers must adhere to these principles. The principles state that demand response shall be 1) flexible and reliable, 2) shall evolve to complement the needs of the grid, 3) shall provide customers with the choice of demand response service provider, 4) shall be implemented in coordination with rate design, 5) shall be transparent, and 6) shall be market-driven leading to a competitive, technology-neutral, open market with a preference for third-party providers and performance based contracts at competitively determined prices. (*See* D.16-09-056 at Ordering Paragraph 8.)

[27] Utilities Proposal, February 17, 2017 at 4-5.

the demand response principles of competitive fairness and transparency and finds the multiple-step process inefficient and unnecessary. A one-step assessment is efficient and provides the necessary transparency required by the demand response principles. The Proposal recommendation for a preliminary assessment should not be adopted.

As previously stated, most parties agree that the Advice Letter process is an efficient process for the purposes of determining whether a provider's demand response program is similar. Marin Clean Energy contends that a Tier Two Advice Letter is the more appropriate level of oversight and argues that once the definition of similar is established, Staff should have adequate direction to make the determination of what constitutes a similar program without the need for a Commission vote on a resolution.[28] In response, the Utilities state that the Tier Two Advice Letter process is ministerial and assert that this process requires a meaningful review by the Commission, staff, the Utilities, and interested parties.[29] In recommending the use of the lengthier application process, CLECA cautions that the Advice Letter process would not suffice due to the fact that along with the cost recovery impact, customers would no longer be able to participate in the similar utility program.[30]

Given that the definition of a similar program is determined herein, the Utilities and other interested persons will be afforded an opportunity to be heard

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[28] Marin Clean Energy Opening Comments on Implementation of Competitive Neutrality Cost Causation Principle, June 19, 2017 at 10-11.

[29] Utilities Reply Comments on Implementation of Competitive Neutrality Cost Causation Principle, July 5, 2017 at 11-12.

[30] CLECA Opening Comments on Implementation of Competitive Neutrality Cost Causation Principle, June 19, 2017 at 8.

by submitting written input in the Advice Letter process, and the Commission will have final approval of the Advice Letter, adopting the use of the Tier Three Advice Letter process strikes a balance of expediency, transparency, and the appropriate level of regulatory oversight.

In comments to the proposed decision and alternate proposed decision, parties reiterated the same arguments regarding the level of regulatory oversight necessary for determining whether a Competing Provider's proposed demand response program is similar to a Competing Utility's program.[31] While these comments do not change the selection of a Tier Three Advice Letter for the review process, it is possible that more or less oversight may be needed in the future. Hence, in the required evaluation of this process, (*see* discussion below) Energy Division is instructed to review the level of regulatory oversight (*i.e.* application versus advice letters) and recommend to the Commission whether a more or less stringent approach is necessary in the future. For the initial process, the Commission should adopt a Tier Three Advice Letter process to determine whether a Competing Provider's proposed demand response program is similar to a Competing Utility's program. The Advice Letter should be served in accordance with General Order 96B.

- Step One A: The Contents of the Advice Letter shall include: 1) a brief overview of the Competing Provider's proposed demand response program, ex ante load impacts for the proposed program in compliance with the adopted load impact protocols, and anticipated start date; 2) customer type description and approximate number of

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[31] AREM-DACC Opening Comments on Proposed Decision, October 5, 2017 at 3-4, CLECA Opening Comments on Proposed Decision, October 5, 2017 at 6-7, and Marin Clean Energy Opening Comments on Proposed Decision, October 5, 2017 at 7-9.

> customers to be marketed to; 3) delineation of the proposed program as either a load modifying resource that is embedded in the California Energy Commission's unmanaged/base case load forecast or a supply resource able to be integrated into the CAISO wholesale market and ability to demonstrate how the program meets either delineation; 4) description of how the Competing Provider will validate to the Commission that its customers will not receive an incentive for the use of prohibited resources during a demand response event; 5) description of whether the Competing Provider's demand response program will use a third party-aggregator; 6) the name of the Competing Utility; 7) the Competing Utility's program(s) that the Competing Provider considers to be similar and an explanation, pursuant to this Decision, and 8) the Competing Utility's previous year's ex ante load impacts for the program(s) as provided in the Competing Utility's annual Load Impact Protocol filings.

This Decision first addresses the elements of a similar demand response program. The Utilities, ORA and OhmConnect agree that a similar program should comply with all demand response related statutes and mandates, be bifurcated into load modifying and supply side resources, and comply with the Commission's rules regarding prohibited resources during demand response events.[32] The Utilities also contend that an assessment of similar should also require similar customer class groups and similar grid benefits.[33] Agreeing with the requirement of similar customer class and program goals, CLECA includes

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[32] *See* ORA Opening Comments on Implementation of the Competitive Neutrality Cost Allocation Principle, June 19, 2017 at 3-4, OhmConnect Opening Comments on Implementation of the Competitive Neutrality Cost Allocation Principle, June 19, 2017 at 2 and 5, and Utilities Proposal, June 19, 2017 at 2-3.

[33] Utilities Opening Comments on Implementation of the Competitive Neutrality Cost Allocation Principle, June 19, 2017 at 2.

the requirements of similar incentive and penalties as well as common program or event parameters.[34] CLECA also provides a dictionary definition of similar: having characteristics in common; alike in substance or essentials.[35]

Arguing that similar does not mean identical, Marin Clean Energy proposes a set of guidelines that describe what similar programs should not be required to be or do.[36] Marin Clean Energy maintains that, to ensure fair competition, the Commission should interpret similar in the broadest possible terms and that requiring other elements adds ambiguity and undermines competitive neutrality. Marin Clean Energy proposes that the only metrics by which a program needs to be deemed similar are whether a program provides the same type of resource: load modifying or supply-side and whether the program is offered to some customers in a particular customer class.[37]

In response, the Utilities assert that such a broad definition of similar would result in all customers in the similar class no longer being eligible for any similar resource demand response program in the Competing Utility's territory. Furthermore, the Utilities contend this definition limits a customer's choice and "significantly diminishes the Commission's power to make demand response a

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[34] CLECA Opening Comments on Implementation of the Competitive Neutrality Cost Allocation Principle, June 19, 2017 at 2-3.

[35] CLECA Opening Comments on Implementation of the Competitive Neutrality Cost Allocation Principle, June 19, 2017 at 2-3, citing the Merriam-Webster Dictionary.

[36] Marin Clean Energy Opening Comments on Implementation of the Competitive Neutrality Cost Allocation Principle, June 19, 2017 at 3-5.

[37] Marin Clean Energy Opening Comments on Implementation of Competitive Neutrality Cost Causation Principle, June 19, 2017 at 3-5 and Marin Clean Energy Reply Comments on Implementation of Competitive Neutrality Cost Causation Principle, July 5, 2017 at 3.

meaningful tool to achieve its goals of grid management and renewable integration."[38]

In developing a definition for what constitutes a similar program, the Commission must balance multiple demand response objectives and principles including: meeting environmental objectives, meeting the needs of the grid, enabling customers to meet their energy needs at a reduced cost, ensuring customers have the right to provide demand response through a service provider of their choice, ensuring demand response processes are transparent, and ensuring demand response activities are market driven and lead to a competitive, technology-neutral, open market with a preference for services provided by third-parties. This Decision strives for simplicity while balancing the multiple objectives and principles.

The Commission does not expect a Competing Provider to provide an exact replica of a Competing Utility's program in order to be deemed similar. In fact, the Commission encourages new and innovative services that could be different from those offered by the Utilities. That being said, Marin Clean Energy's broad definition of similar could result in a Utility losing the ability to market any supply side resource to all the Competing Provider's residential customers in a particular Community Choice Aggregator or Direct Access provider's territory. For example, if the Commission adopted this broad definition of similar and the Competing Provider's program is only offering a single supply-side program to a small subset of its residential customers, the other residential customers served by the Competing Provider would have no

[38] Utilities Reply Comments on Implementation of Competitive Neutrality Cost Causation Principle, July 5, 2017 at 5.

access to demand response incentives. Furthermore, the Competing Utility could lose the load impact it currently attains from the Competing Provider's residential customers during demand response events and, most importantly, the State may not attain the same load impact through the similar smaller program.

Accordingly, this Decision denies the request by Marin Clean Energy to interpret similar in the broadest possible terms by only looking at whether a program is offered to a subset of the same customers and if the program is either load modifying or a supply side resource. Instead, this Decision requires that, in the advice letter, the Competing Provider describe the customer type and provide the approximate number of customers to whom its proposed demand response program will market. This will allow the Commission to ensure that a large group of customers are not omitted from demand response opportunities. This Decision finds that a similar program requires that the customer type and approximate number marketed to are "alike in substance or essentials." Therefore, in order to be deemed similar, the type of customer and approximate number of customers marketed to in the Competing Provider's program should be similar to the Competing Utility program's customer type and approximate number of Competing Provider's customers to which the utility currently markets the similar program(s).

All parties agree that the Competing Provider should designate the demand response resource type this program will target. A similar resource type should comport with Commission definitions of load modifying or supply resource and either be counted in the California Energy Commission's forecast or be able to be integrated into the CAISO market and comply with all CAISO market rules. The Competing Provider shall provide the resource type in the advice letter, as well as information demonstrating how the resource meets the

Commission's definition of that resource, i.e., evidence of how it will be counted in the California Energy Commission's forecast or plans on how the program will be integrated into the CAISO market and will comply with all CAISO rules.

Some parties contend that a similar program should meet all demand response mandates and environmental policies.[39] Marin Clean Energy maintains that, as a Community Choice Aggregator, it was founded to expand procurement of renewables and reduce greenhouse gas emissions. Furthermore, Marin Clean Energy contends that Community Choice Aggregators perform above and beyond state mandates, setting more aggressive energy policy goals than the state requires. Surmising that the clean energy goals of California and Community Choice Aggregators are aligned,[40] Marin Clean Energy argues that imposing such requirements on a similar program is redundant but also unnecessary because demand response resources, by their nature, meet California's clean energy policies.[41] In response, the Utilities reference directives that Load Serving Entities are required to meet including Pub. Util. Code §§ 454.52 and 454.51, which addresses greenhouse gas emissions targets.[42] Both OhmConnect and ORA point specifically to the Commission's policy on the use of prohibited resources during demand response events and maintain that a

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[39] CLECA Opening Comments at 4-5, Utilities Opening Comments at 2-3, ORA Opening Comments at 3-4, and OhmConnect Opening Comments at 5.

[40] Marin Clean Energy Opening Comments to Implementation of Competitive Neutrality Cost Allocation Principle, June 19, 2017 at 5-6.

[41] Marin Clean Energy Reply Comments to Implementation of Competitive Neutrality Cost Allocation Principle, June 19, 2017 at 2.

[42] Utilities Opening Comments at 5-6.

similar program should comply with this policy.[43] ORA contends that in order to meet resource adequacy requirements, a resource should comply with the prohibited resources policy and highlights that demand response is not a clean resource if the prohibited resource policy is not followed.[44] Marin Clean Energy agrees that all Load Serving Entities, including Marin Clean Energy, must comply with resource adequacy requirements, renewable portfolio standards, energy storage statutes, and integrated resource planning but contends that imposing any additional requirements, *i.e.,* prohibited resources compliance, would create greater cost barriers to Community Choice Aggregators and their customers.[45] Additionally, Marin Clean Energy argues that the Commission's prohibited resources policy is not state-mandated, and therefore Marin Clean Energy should not be required to comply with the policy.[46]

This Decision continues the theme of balancing competing objectives. As noted by the Utilities, all load serving entities, including Community Choice Aggregators and Direct Access electric service providers are required to comply with Pub. Util. Code § 454.52, which requires these entities to file an integrated resource plan to (among other things) ensure that load serving entities meet greenhouse gas emissions reduction targets, procure 50 percent eligible renewable energy resources by 2030, enhance demand-side management, and minimize local pollutants. Therefore, requiring a Competing Provider's similar program to adhere to all environmental requirements is redundant of the

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43 ORA Opening Comments at 4 and OhmConnect Opening Comments at 5.

44 ORA Reply Comments at 1-2.

45 Marin Clean Energy Opening Comments at 6-10.

46 *Id.* at 10.

requirements in Pub. Util. Code § 454.52. Furthermore, all load serving entities are required to comply with resource adequacy requirements, including reporting load impacts. The Commission reviews these requirements in the resource adequacy proceedings. Hence, there should be no need to duplicate these efforts through the process adopted here. However, if a Competing Provider does not seek resource adequacy credit for its demand response, there is no way for the Commission to determine the overall state load impacts of demand response programs. Therefore, once deemed similar, no later than April 1 each year the Competing Provider shall submit, to the Director of the Commission's Energy Division, the annual load impacts of the Competing Provider's similar demand response program in compliance with the adopted load impact protocols.

Furthermore, for the purposes of determining the impact of the Principle's implementation in an evaluation of this process, it is reasonable for the Commission to require a Competing Provider to provide ex ante and ex post load impacts. Ex ante load impacts of the proposed similar program(s) in compliance with the adopted load impact protocols shall be provided by the Competing Provider with the Tier Three Advice Letter and ex post load impacts of the deemed similar program(s) in compliance with the adopted load impact protocols shall be required as part of the evaluation reporting discussed below.

The Commission has previously determined that fossil-fueled back up generation is antithetical to the efforts of the Commissions Energy Action Plan and the Loading Order.[47] Hence, in order for a Competing Provider's program

[47] D.16-09-056 at Finding of Fact No. 7.

to be similar it should not use prohibited resources to enable load shed during demand response events. To be deemed similar, a Competing Providers' demand response program must demonstrate that the program can validate adherence to the Commission's prohibited resource policy.

Arguing that the prohibited resource policy does not apply to Community Choice Aggregators because it is not a state requirement, Marin Clean Energy further holds that extension of the policy to non-utility electricity providers was neither considered nor addressed in D.16-09-056.[48] Marin Clean Energy states that it anticipates that Competing Providers "will administer demand response programs that ensure procurement of greenhouse gas-free resources."[49] However, Marin Clean Energy's expectations of clean demand response do not provide the Commission with sufficient assurance that load shed will not be substituted with prohibited resources that add to California's greenhouse gas levels. While it may be true that the Commission cannot require Community Choice Aggregators to comply with the prohibited resource policy, the Commission can require proposed demand response programs to comply with the policy to be deemed similar. Moreover, the purpose of the Competitive Neutrality Cost Causation Principle is to provide a level playing field for all demand response providers. Thus, if the Utilities must comply with the prohibited resource policy, it is fair to require a Competing Provider to comply with the policy.

With respect to the elements of a similar demand response program, this decision also addresses the question of customer choice. One could argue that

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48 Marin Clean Energy Opening Comments to Proposed Decision, October 5, 2017 at 4.

49 *Ibid*.

customers already have a choice when determining their load serving entity and choosing between an investor-owned utility, a Community Choice Aggregator or another energy service provider. However, the Commission has spent a great deal of time and effort in ensuring that third-party entities (*e.g.,* demand response providers and aggregators) have a level playing field in order to increase customer choice and provider competition. Hence, in order to be deemed similar, a Competing Provider's program should also allow for third-party providers' participation if the Competing Utility's program also allows for third party provider's participation. This requirement comports with the Commission's demand response principle regarding customer choice.

Lastly, in addition to the items discussed above and in order to facilitate the analysis of the advice letter, this Decision requires the Competing Provider to also include in the advice letter: the name of the Competing Utility, the Competing Utility's demand response program(s) that is/are similar to the Competing Provider's proposed similar program(s) and the most recent load impacts reported for the Utility's demand response program(s), the ex ante load impacts of the Competing Provider's proposed similar program in compliance with the adopted load impact protocols, and an explanation of how the proposed programs' similarities comply with this Decision. This should accelerate the staff analysis and should lead to an expedient regulatory process.

- Step Two: The Tier Three Advice Letter will include a protest period, staff analysis, and proposed resolution. This process will follow the same process as outlined in General Order 96B.

As previously stated, the use of the Tier Three Advice Letter process strikes a balance of expediency, transparency and the appropriate level of regulatory oversight. The Tier Three Advice Letter process will provide parties an opportunity to comment on the contents of the Advice Letter and allow the Competing Provider to respond to any concerns voiced. Commission Staff will review the contents of the Tier Three Advice Letter and any protests and responses. If necessary, Staff may request additional information. Furthermore, if appropriate, Staff may consider holding a workshop to assist in understanding stakeholder positions. To ensure expediency, Staff should comply with the time process outlined in General Order 96B.

- Step Three: If the outcome of the resolution determines that the Competing Provider's proposed demand response program is similar, the Competing Utility has 30 days from the issuance of the resolution to begin the process to cease cost recovery by and targeted marketing to the Competing Provider's customers of the similar program. By the 60th day, a letter shall be sent by the Competing Utility to the affected customers notifying them of the change. The letter will also explain to customers of the Competing Provider currently enrolled in the Competing Utility's similar demand response program that they will cease to be eligible for that program at the end of the implementation period but will be eligible to participate in the Competing Provider's similar demand response program. No later than 365 days following the issuance of the resolution (the end of the implementation period), the Competing Utility shall complete the changes.

The Competitive Neutrality Cost Allocation principle requires that no later than one year after implementation of a demand response program the Competing Utility shall cease cost recovery of and targeted marketing to the customers of the Competing Provider's similar program. This Decision regards the determination of whether a program is similar as the beginning of the implementation period. Once the Commission makes such a determination, the Competing Utility has one year to cease cost recovery and targeted marketing to the Competing Provider's customers of the program(s) deemed to be similar. Shell objects to the process recommended in the Utility's Proposal and argues that the Competing Utility should be able to remove corresponding costs within two billing cycles. The Commission has already made its determination on this issue in D.14-12-024; the one-year period will not be re-litigated in this Decision. Furthermore, in order to limit customer confusion, the Competing Utility, in coordination with the Competing Provider with the deemed similar demand response program, shall provide a letter to the affected customers (*i.e.,* the Competing Provider's customers to whom it will market the demand response program(s) deemed similar) explaining the process and alerting them to the impending change.

- Step Four: Within one billing cycle following the end of cost recovery and marketing of the similar demand response program by the Competing Utility, affected customers shall receive a bill credit for the similar program(s).

The Utilities recommend the use of a credit on the Competing Provider's affected customers' bills and suggest a stakeholder workshop process to develop the method to determine the credit. Marin Clean Energy argues the use of a bill credit would cause customer confusion. No party provided any reasonable alternative.

In Step Three, this Decision requires a letter to be sent to affected customers, as defined above, explaining the implementation of the competitive neutrality principle. This letter can also serve as a venue to explain the bill credit, thus eliminating customer confusion.

Additionally, this Decision adopts a public process to develop an approach to determine the bill credit. Within 90 days of the issuance of this Decision, the

Utilities shall serve a proposed approach and a draft standardized form letter (as required by Step Three) to all parties to this proceeding. No later than 30 days later, parties may comment on the approach and letter via informal comments to the service list. Within 60 days after the proposed approach and draft letter is served to parties, but after parties have provided comments, the Commission's Energy Division shall facilitate a workshop to discuss the proposed approach and develop a consensus; workshop participants should also address the standardized letter(s) All parties and other interested persons are advised to participate because the same basic approach will be used by the Utilities. However, this Decision also recognizes that utility systems are not exactly the same and may require slightly different approaches by each utility. Within 30 days after the workshop, the Utilities shall submit a Tier Three Advice Letter that either i) proposes the consensus approach or ii) includes and describes all the discussed options and proposes one of the options. The Utilities may include in this Tier Three Advice Letter, a proposal for recording incremental costs associated with implementing the bill credit approach, a forecast of the activities and costs, and the proposed rate recovery. The bill credit approach, if approved by the Commission, shall not commence until a Competing Provider's program is deemed similar via Resolution, thus starting the one year implementation clock.

The Utilities request cost recovery of stranded costs but provide no evidence that stranded costs exist. Hence, this Decision does not address the issue of recovery of stranded costs. However, a Utility may include a request for recovery of any such stranded costs in an application for recovery of costs to implement the bill credits in accordance with the procedures adopted through the Tier Three Advice Letter process. The Utilities request to include this cost recovery in the 2020 demand response portfolio update. This request is denied as the recovery of stranded costs could require an evidentiary hearing and the 2020 portfolio update uses an advice letter process, which does not allow for an evidentiary hearing.

As the Commission is embarking upon new territory with the implementation of the Competitive Neutrality Cost Causation Principle, it is prudent to review the implementation to ensure the process and the principle itself is achieving the intent of the Commission. Furthermore, the Commission should also ensure that the implementation of the principle does not create unintended consequences that could undermine the State's ability to meet the demand response goal and associated objectives and principles adopted by the Commission.

The Commission's Energy Division should provide the Commission with a report that reviews and evaluates: (1) the implementation process (including the level of regulatory review) based on information and feedback on the four-step process received from any successful Competing Provider and the Competing Utility; (2) any demand response elements negatively affected by the implementation of the principle including: customer satisfaction, the Competing Utility's program participation in terms of numbers of customers, the load impact on a Competing Utility's demand response program, and the approximate load impact attained by the Competing Provider's similar program; and (3) recommendations for any changes to address identified negative impacts. The Competing Provider(s) shall submit all data requested by Energy Division; the scope and timing of the data request will be addressed in the resolution determining whether a Competing Provider's program is similar. The report should be provided to the Commission three years following the adoption of the resolution granting a Competing Provider's program similar status.

PG&E and SCE recommend a continuing evaluation process to include submitting load impacts. As Load Serving Entities, the Competing Providers are required to provide load impacts in the resource adequacy proceeding. Hence, duplication of this effort is not required here. However, PG&E and SCE caution the Commission of future load migration from the Utilities to the Competing Providers and the impact on demand response. The Utilities are authorized to provide a report on load migration to community choice aggregator and direct access electric service provider customers in the 2023-2027 demand response portfolio applications.

The Competitive Neutrality Cost Causation Principle is implemented to create a level playing field between non-utility electric service providers and the Utilities. Nothing in this Decision prohibits a third-party provider from continuing to market their demand response services to non-utility electric service provider's customers, except those providing the service through a utility's demand response program. This Decision confirms that the Demand Response Auction Mechanism, if adopted as a permanent mechanism, is not eligible for the Competitive Neutrality Cost Causation Principle implementation because the auction mechanism is a procurement mechanism designed to allow third party direct participation into the CAISO market; it is not a demand response program. That being said, a Competing Provider's demand response program is eligible to be bid into a future solicitation of the Demand Response Auction Mechanism, if adopted as a permanent mechanism. Furthermore, pilots are also not eligible for similar status because they are not considered to be fully implemented programs.

2.2. Demand Response Auction Mechanism Pilot

This Decision orders PG&E, SCE and SDG&E to conduct an additional solicitation in 2018 for the third Pilot for contracts for deliveries in 2019 for the following reasons: lack of alternative opportunities for growth in demand response provided by third parties, to support the market for competitive demand response, to elicit further evidence whether the Pilot market may be consolidated or suffering from limited opportunities, and to assess and test the procurement guidelines for the demand response auction mechanism that the Commission adopted in D.16-09-056, which to date have not been incorporated into the Pilot design. This Decision also finds it prudent to gain more experience prior to the completion of the Pilot evaluation to further inform a Commission decision whether to move forward with making the auction a permanent mechanism.

2.2.1. Demand Response Auction Mechanism Pilot Background

An objective for this rulemaking is to consider the adoption of a competitive procurement process to ensure cost-effective and reliable demand response resources for California and to engage new third parties and customers.[50] D.14-12-024 directed the Utilities to participate collaboratively in a working group to develop a design, protocol, standard contract and standard evaluation criteria for the Pilot. The purpose of the Pilot is to gain experience in the CAISO market and investigate whether a competitive procurement

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[50] R.13-09-011, September 19, 2013 at 18.

mechanism for supply side resources outside of traditional utility programs is viable.[51]

An initial auction took place in the spring of 2015 with delivery in 2016 and a second auction took place in the spring of 2016 with delivery in 2017. The Commission authorized budgets of $9 million for the 2015 auction, as approved in Resolution E-4728 and $13.5 million for the 2016 auction, as approved in Resolution E-4754. D.16-06-029, which approved bridge funding for 2017 demand response program and activities, directed the Utilities to expand upon the experience from the first two years of the Pilot by conducting a third auction in 2017 with delivery in 2018. D.16-06-029 authorized a budget of $27 million. Shortly thereafter, D.16-09-056 directed the Commission's Energy Division to conduct an evaluation of the Pilot reasoning that if the Commission approves implementation of a permanent auction mechanism, the timing of evaluation steps will allow the Utilities to begin administering annual auctions in 2019 for 2020 and beyond delivery. In response to D.16-06-029, Resolution E-4817 approved the use of contracts of up to two years for continuation of the Pilot with an auction in 2017 and deliveries in 2018 and 2019. The Resolution directed the Utilities to apply the $27 million budget authorized in D.16-06-029 to incentive and administration payments to occur in 2018 and 2019, as well as administrative mechanism costs incurred in 2016 and 2017.

The Joint Demand Response Parties filed a petition for modification of D.16-06-029 requesting the Commission: i) to clarify that the funding originally authorized for a third year of the Pilot was for program year 2017 and, in order

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[51] D.14-12-024 at 12 and D.16-06-029 at 42.

for the Commission to appropriately address the growth of the Pilot as it intended, ii) to revise D.16-06-029 so as to double the authorized funding. The Joint Demand Response Parties argue that the authorized funding level limited participation growth, which could result in damage to the businesses of the Joint Demand Response Parties.

In D.17-04-045, the Commission denied the request by the Joint Demand Response Parties to increase the budget for the Pilot because the record did not support doubling the budget due to the additional second year of delivery. However, the Commission recognized the potential for the adopted budget to limit the opportunities for growth by demand response customers and providers in a manner inconsistent with D.16-06-029 and D.16-09-056. Thus, D.17-04-045 directed parties to respond to a set of questions in order to complete the record on this issue. Parties were asked whether demand response providers' business opportunities are limited without a 2018 auction for deliveries in 2019 and, if approved, what the parameters of the auction should entail.

In response to the questions in D.17-04-045, the Joint Demand Response Parties and OhmConnect express support for an additional 2018 auction for deliveries in 2019, stating that the combination of ending and capping programs with little increase in the Pilot megawatts is "stymieing demand response growth in the state by severely limiting program option for customers." The Utilities and ORA oppose the additional auction, although in comments to the alternate proposed decision ORA stated that it does not oppose an additional auction if it requires program design elements that will lead to the competitive procurement of demand response from third parties.[52] SDG&E maintains that providers have had ample business opportunities.[53] While arguing that an additional auction may only provide limited opportunities, SCE also notes that there were fewer awarded bidders in 2017 with nearly twice the procured megawatts.[54] Furthermore, PG&E contends that additional megawatts procured through a 2019 auction would have negative value for ratepayers.[55] Additionally, ORA opines that the current Pilot structure may not further the Commission's goals, so it would be more prudent to await the results of Energy Division's evaluation of the Pilot.[56] Parties also commented on appropriate parameters should the Commission approve a 2018 auction for additional deliveries in 2019, including budget level, procurement guidelines, and procurement criteria.

2.2.2. Approval of Additional Auction for 2019 Delivery for the Demand Response Auction Mechanism Pilot

This Decision finds it is reasonable to require PG&E, SCE and SDG&E to conduct an additional 2018 auction for contract deliveries in 2019 given: 1) the limited opportunities for third party providers in 2019, 2) to support the market for competitive demand response while the Commission determines how demand response will be procured in the future, 3) the opportunity to gain further evidence on whether the third party demand response provider market

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[52] ORA Opening Comments on the Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 2. As discussed further below we are accepting ORA's proposed change to utilize bid selection criteria adopted in Ordering Paragraph 12 of D.16-09-056.

[53] SDG&E Opening Response to Questions in D.17-04-045, July 6, 2017 at 1-2.

[54] SCE Opening Response to Questions in D.17-04-045, July 6, 2017 at 2.

[55] PG&E Opening Response to Questions in D.17-040045, July 6, 2017 at 1.

[56] ORA Opening Response to Questions in D.17-04-045, July 6, 2017 at 4.

may be consolidating or has been stymied by limited opportunities, and 4) the opportunity incorporate into the Pilot design and test procurement guidelines for a permanent demand response auction mechanism that the Commission adopted in D.16-09-056. When the Commission first authorized the Pilot in D.14-12-024, it noted that a pilot is a cost-effective way of implementing an idea, learning from that idea, and making changes to improve its success. While the Commission has embarked upon an evaluation of the Pilot and anticipates the results of the evaluation in 2018, this Decision concludes that the Commission can learn from an additional auction, consistent with the original objectives of conducting the Pilot. Once the evaluation is complete, and considering any additional insights gained from the auction authorized by this Decision, the Commission can determine whether to adopt the Pilot as a permanent activity and whether a permanent mechanism requires revision of the parameters established in D.16-09-056, Ordering Paragraph 12.

The Joint Demand Response Parties and OhmConnect contend that without an additional auction for 2019 deliveries: 1) third-party demand response providers have limited business opportunities and 2) the Utilities will have difficulty increasing their contracted Pilot capacity in order to comply with directives in D.16-09-056 to procure up to one gigawatt of demand response in 2020. Furthermore, the Joint Demand Response Parties and OhmConnect maintain that the limited growth between the 2018 and 2019 scheduled deliveries correlates to the flat funding between the two years, because while the total budget authorized doubled from the second to the third pilot solicitation, the third pilot was required to cover two full years of procurement (*i.e.*, $13.5 million each in 2018 and 2019).[57] OhmConnect and the Joint Demand Response Parties point to the elimination of the Aggregator Managed Portfolio contracts and the waitlist for new enrollments in the Base Interruptible Program as evidence of diminishing business opportunities.[58]

In response to the issue of limited opportunities, SDG&E provides a list of opportunities demand response providers have had to secure a contract for deliveries in 2019 including: 2014 All Source Least Cost Resource Request for Offer, 2016 Preferred Resources Least Cost Resource Request for Offer, 2018-2019 Pilot Request for Offer, Distribution Resources Plan Demonstration Project C, and the Integrated Distributed Energy Resource Incentive Pilot.[59] PG&E, SCE and ORA also point to the Capacity Bidding Program as an alternative opportunity for Demand Response Providers.[60] The Joint Demand Response Parties clarify in response that the Capacity Bidding Program is only available to commercial and industrial customers, and that only PG&E has proposed expanding it to residential customers.[61] In its reply comments, PG&E points out that the megawatts procured for 2019 in PG&E's 2018-2019 Pilot auction exceeds the capacity of PG&E's Aggregated Managed Portfolio program before its closure.[62]

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57 Joint Demand Response Parties Comments to D.17-04-045, July 6, 2017 at 3.

58 OhmConnect Opening Comments to D.17-04-045, July 6, 2017 at 1-2 and Joint Demand Response Parties Opening Comments to D.17-04-045, July 6, 2017 at 5.

59 SDG&E Opening Comments to D.17-04-045, July 6, 2017 at 1-2.

60 ORA Opening Comments to D.17-04-045, July 6, 2017 at 3-4, PG&E Opening Comments to D.17-04-045, July 6, 2017 at 3, and SCE Opening Comments to D.17-04-045, July 6, 2017 at 2.

61 Joint Demand Response Parties Reply Comments to D.17-04-045, July 17, 2017 at 7.

62 PG&E Reply Comments to D.17-04-045, July 17, 2017 at 3.

PG&E's comments to D.17-04-045 and comments on the alternate proposed decision show that the combined size of its aggregator managed programs, including aggregator-provided base interruptible programs, has declined from 2016 to 2019.[63] PG&E asserts that growth in Pilot megawatts procured in 2019 compared to 2016 demonstrates growth in business opportunities; however, this reflects the Commission's decisions to continue the Pilot and increase budgets after the first auction in 2015 but does not demonstrate a current increase in business opportunities to sustain growth of third party providers in 2019. By contrast, as explained below we find a flattening of growth in capacity procured through the demand response auction mechanism in 2019.

Further, while demand response providers have had several business opportunities to bid on contracts for deliveries in 2019, the Commission has already determined that although nothing precludes the Utilities from procuring demand response through other competitive solicitations, as a policy matter the Commission adopted the demand response auction mechanism as the primary tool to fulfill its goals of expanding the role of demand response and third-party providers.[64] All-source solicitations conducted for 2014 and 2016 do not provide current business opportunities to sustain the growth of third party demand response. In comments to the alternate proposed decision parties also pointed out that the past solicitations pre-dated the implementation of Rule 24/32, which allows third party demand response providers to participate directly in the

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63 PG&E Reply Comments to D.17-04-045, July 17, 2017 at 3, n.10; PG&E Opening Comments on the Alternate Proposed Decision, October 5, 2017 at 2-3 (showing total of all opportunities available to aggregators, excluding the demand response auction mechanism Pilot contracts but including other pilots, declined from 186 megawatts in 2016 to 172 megawatts in 2019).

64 D.16-09-056 at 71.

California Independent System Operator (CAISO) markets.[65] We are also persuaded by comments in response to the alternate proposed decision that the Distribution Resources Plan Demonstration Projects and Integrated Distributed Energy Resource Incentive Pilot are limited in scope, designed to fulfill a different set of grid services than CAISO-integrated demand response, and will not all provide business opportunities for third party demand response providers in 2019.[66] This Decision finds that although some utility programs remain available to non-utility providers, even with other solicitation opportunities pointed out by the parties, business opportunities in 2019 for third party demand response providers are limited without a 2018 auction. This Decision further finds that other opportunities do not further the purpose of the Pilot or the Commission policy adopted in D.16-09-056.

Parties opposed to holding an additional auction for 2019 deliveries also argue that there is no need for another auction. SDG&E maintains that the need for another auction should be the determining factor, not the need for business opportunities.[67] PG&E argues that the 2018-2019 Auction resulted in its procurement of 80 megawatts in August 2018 and 90 megawatts in August 2019, over 40 percent and 60 percent above 2017 megawatt levels, respectively.[68] SDG&E procured 13.9 megawatts in August for 2018 and 15.7 megawatts for

[65] OhmConnect, Electric Motor Werks, and Stem Joint Opening Comments on the Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 4.

[66] OhmConnect, Electric Motor Werks, and Stem Joint Opening Comments on the Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 4-5.

[67] SDG&E Reply Comments to D.17-04-045, July 17, 2017 at 1.

[68] PG&E Opening Comments to D.17-04-045, July 6, 2017 at 2. Confidentiality Rules require the identity of the competitors remain anonymous.

2019.[69] SCE procured 88.5 megawatts in 2018 and 99.2 megawatts in 2019.[70] As indicated in the Utilities' Advice Letters, the increases in 2019 deliveries compared to 2018 were 12.5 percent for PG&E, 13 percent for SDG&E, and 12 percent for SCE.[71] Although the initial third Pilot auction demonstrated growth relative to the second Pilot auction, the results confirm the characterization by the Joint Demand Response Parties of modest growth over the two-year delivery period and concerns that the flatter budgets would not provide significant growth.[72] This Decision finds that the one year budget with a solicitation divided over two years of delivery did lead to a flattening of growth in capacity procured through the demand response auction mechanism and limited business opportunities for demand response providers.

We are also persuaded by CAISO's comments to the alternate proposed decision that providing continuous annual funding for utility programs with no solicitation for competitively procured demand response in 2018 may harm third parties' ability to compete on a level playing field and cause the nascent competitive market to wither.[73] Similarly, the Joint Demand Response Parties assert in comments to the alternative proposed decision that a failure to continue the solicitation process in succession could have negative repercussions in the

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[69] Advice Letter 3095-E (SDG&E), Attachment B.

[70] Advice Letter 3629-E (SCE) at 4. SCE procured 56.2 megawatts for 2017. SCE Opening Comments to D.17-04-045, July 6, 2017, at 3.

[71] Advice Letter 5109-E (PG&E), 3095-E (SDG&E), and 3629-E (SCE).

[72] Joint Demand Response Parties Opening Comments to D.17-04-045 at 3.

[73] CAISO Opening Comments on Proposed Decision and Alternate Proposed Decision, October 5, 2018 at 1-2.

market.[74] As a policy determination, we find that requiring an additional auction is reasonable to support the emerging market for competitive demand response while we establish a final policy on how demand response capacity will be procured in the future.

PG&E states that another indication of the lack of need is in the Independent Evaluator's Report from the 2018-2019 Pilot solicitation, which found "significant consolidation in the market."[75] PG&E cites the findings of the Independent Evaluator from Advice Letter 5109-E, which describe the number of participants and responses from participants providing residential offers as declining between the second auction solicitation and the third, and notes that two major competitors dominated the offers submitted.[76] In response, the Joint Demand Response Parties point out that the Independent Evaluator reports for PG&E and SDG&E indicate the response of the market was reasonably robust to generate a competitive market response.[77] They further reason that the uncertainty facing the market regarding change in Resource Adequacy availability hours, dispatch time, and the absence of a fully implemented e-signature process may have come into play with the decline in the number of bidders.[78] Finally, the Joint Demand Response Parties assert that a stand-alone auction in 2018 for 2019 deliveries would not be hampered with the same

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[74] Joint Demand Response Parties Opening Comments on Proposed Decision and Alternate Proposed Decision, October 5, 2018 at 9;

[75] PG&E Reply Comments to D.17-04-045, July 17, 2017 at 2.

[76] PG&E Opening Comments at 2 and Reply Comments at 2.

[77] OhmConnect Opening Comments to D.17-04-045, July 6, 2017, at 4-5. [78] Joint Demand Response Parties Opening Comments to D.17-04-045, July 6, 2017 at 4-5.

[78] Joint Demand Response Parties Opening Comments to D.17-04-045, July 6, 2017 at 4-5.

uncertainties because the "click-through" processing rules are being finalized,[79] and have now been adopted by the Commission.[80] SCE also anticipates that resolution of the click through process in late 2017 will reduce a recruitment barrier to demand response auction sellers.[81]

The Independent Evaluator's report is disconcerting in that it may demonstrate that market factors, regulatory uncertainties, or limited business opportunities may have discouraged new entrants. This provides further evidence that the Commission should authorize an additional auction for 2019 deliveries before the evaluation of the Pilot is complete. In comments to the alternate proposed decision, ORA also proposes the Commission use an additional auction to test the procurement guideline adopted D.16-09-056, Ordering Paragraph 12(a), (c), and (d), which have not all previously been applied in the Pilots.[82] We are persuaded that an additional 2018 Pilot auction provides a valuable opportunity to test these procurement guidelines. This Decision finds that requiring the Utilities to conduct an additional auction in 2018 using the permanent procurement guidelines adopted in OP 12 of D.16-09-056 will provide useful information for the Commission's evaluation of the Pilots. Results from an additional auction can provide further insights into the evolving state of the market, including consolidation and other evaluation criteria such as whether procurement guidelines adopted in D.16-09-056 should

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[79] Joint Demand Response Parties Reply Comments to D.17-04-045 at 8.

[80] Resolution E-4868 (Click-Through Authorization), adopted August 24, 2017.

[81] Advice Letter 3629-E (SCE) at 9.

[82] ORA Opening Comments on the Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 7.

be modified if the Commission adopts a permanent demand response auction mechanism. The Energy Division will include a discussion of this information gained from the additional auction as part of its evaluation of the Pilot. This Decision finds that it is prudent to allow for an additional pilot auction in 2018 to supplement the procurement contracted under the third Pilot for deliveries in 2019.

Parties also respond to the Joint Demand Response Parties and OhmConnect's contention that a 2018 solicitation would provide a "glide path" to the one gigawatt demand response procured through the permanent auction mechanism, if adopted by the Commission.[83] ORA correctly clarifies that the Commission does not consider the one gigawatt figure to be a procurement target. ORA explains that the Commission reasoned that the size of the mechanism should be flexible based on the competitiveness of the bids received and capped the annual procurement at one gigawatt.[84] In reply, the Joint Demand Response Parties argue that the Commission has determined that the parameters of the demand response auction mechanism state that the mechanism is the primary means of soliciting demand response and the one gigawatt figure is the ceiling.[85] In D.16-09-056, the Commission adopted a policy of using 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

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[83] Joint Demand Response Parties Opening Comments to D.17-04-045, July 6, 2017 at 5 and OhmConnect Opening Comments to D.17-04-045, July 6, 2017 at 2.

[84] ORA Reply Comments to D.17-04-045, July 6, 2017 at 2.

[85] Joint Demand Response Parties Reply Comments to D.17-04-045, July 17, 2017 at 5.

providers, subject to the one gigawatt limit.[86] This Decision finds that the total 203 megawatts the Utilities have procured for deliveries in 2019 through the auction mechanism is far below the one gigawatt ceiling adopted in D.16-09-056. Thus, while one gigawatt is a ceiling and not a target or procurement requirement, holding an additional auction in 2018 is not inconsistent with D.16-09-056. Prior to the completion of the Pilot evaluation and a determination by the Commission of whether to adopt the auction mechanism as permanent, an additional solicitation for 2019 deliveries furthers the Pilot objectives and is consistent with the parameters and policies adopted in D.16-09-056 and shall be implemented according to the parameters adopted below.

PG&E also asserted in its opening comments that it has no need for resource adequacy procurement for 2019 and thus any further growth in the demand response auction mechanism for 2019 deliveries by definition has a negative value for PG&E's ratepayers.[87] SCE and SDG&E's opening and reply comments did not state whether these utilities need to procure additional resource adequacy for 2019. In comments to the alternate proposed decision the CAISO asserts that relying on resource adequacy need as a policy rationale to decline to require PG&E to conduct an additional competitive demand response auction in 2018 is inconsistent with leaving in place policies that continue to fund the Utilities demand response programs over the same time period.[88] The record

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[86] *Id*. and D.16-09-056 at 71.

[87] PG&E Opening Comments to D.17-04-045, July 6, 2017, at 1.

[88] CAISO Opening Comments on Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 2. Other parties also recommend modifying the alternate proposed decision to *require* PG&E to hold the additional auction, rather than *authorizing* PG&E to hold an additional auction. *See* Joint Demand Response Parties Opening Comments to Proposed Decision and

Footnote continued on next page

is not well developed on the issue of resource adequacy need; even if a utility has excess system resource adequacy it may still need to procure local capacity in 2019 for transmission constrained areas or sub-areas. Moreover, the Commission's decision to implement the demand response auction mechanism Pilots is not based on a need for resource adequacy, it reflects a policy determination to expand the role of demand response and third-party providers.[89] Accordingly, we clarify that our Decision today is not based on a consideration of resource adequacy procurement needs in 2019.

The theme throughout this Decision is balancing competing objectives. We continue this theme by balancing the objectives of the Pilot with the principles of demand response. The Commission pursued the Pilot to gain experience in the CAISO market and to investigate whether a competitive procurement mechanism for supply side resources outside of traditional utility programs is viable. Requiring the Utilities to conduct an additional auction for 2019 will achieve these objectives and aid in the Commission's informed consideration of the Pilot's full merits.

This Decision approves an additional Pilot auction for contracts for delivery in 2019 to PG&E, SCE and SDG&E within the parameters specified below. The record indicates that while there have been some opportunities for demand response providers to bid on procurement contracts, growth opportunities for third party demand response providers have been limited.

Alternate Proposed Decision, October 5, 2017 at 3, 6-7; OhmCnnect, Electric Motor Werks, and Stem Joint Opening Comments on Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 2 and 11.

[89] D.16-09-056 at 71.

Furthermore, the Commission is troubled by concerns expressed about the strength and competitiveness of the market, given the contents of the Independent Evaluator's report. An additional auction for 2019 deliveries can bring further evidence to bear on these issues. It will also allow the Commission, for the first time, to test and assess the use of the procurement parameters adopted in D.16-09-056 during its evaluation of the demand response auction mechanism. If the evaluation, further informed by results of an additional auction, provides evidence that the parameters adopted in D.16-09-056 are not appropriate, the Commission could reconsider those parameters.

2.2.3 Requirements for the Additional Auction for Contracts for Delivery in 2019

In response to D.17-04-045, parties commented on what auction parameters and procurement criteria should be adopted if the Commission approves an additional auction for deliveries in 2019. This Decision finds that it is reasonable for the Utilities to conduct a 2018 auction for additional contracts for delivery in 2019 using the same procurement guidelines and procurement parameters as the initial third Pilot auction, consistent with Resolution E-4817 and D.16-06-029 as modified by D.17-04-045, with the exceptions specified below relating to the bid selection criteria.[90] This Decision authorizes an additional budget of $6 million each for SCE and PG&E and $1.5 million for SDG&E.

In regard to budget, the Utilities advocate for a limited budget of $2 million for PG&E and SCE and $500,000 for SDG&E.[91] SCE argues that this would effectively double the budget for the 2019 delivery year compared to 2016

[90] *See* D.17-04-045 at 13 and Ordering Paragraphs 3-5.

[91] PG&E Opening Comments to D.17-04-045, July 6, 2017 at 3-4, SCE Opening Comments to D.17-04-045, July 6, 2017 at 3-4, SDG&E Opening Comments to D.17-04-045, July 6, 2017 at 2-3.

(which was the first delivery year of the Pilot).[92] The Joint Demand Response Parties suggest a budget of $27 million as an "appropriate budget trajectory."[93] ORA advocates for a total budget of $13.5 million, with PG&E's and SCE's budgets each capped at $6 million and SDG&E's at $1.5 million. ORA observes that this amount is half of the authorized budget of the 2017 solicitation that covered deliveries in both 2018 and 2019 and is the same amount authorized for the 2016 auction for deliveries in 2017. ORA reasons that $13.5 million is an acceptable funding level given that the Commission found in D.17-04-045 that the record did not support a doubling of budget for the 2017 auction.[94]

Our rationale for ordering an additional auction for 2019 deliveries is to ensure sufficient growth opportunities for third party demand response services and support the market, consistent with Commission policy as articulated in D.17-04-045.[95] We also expect the auction will provide further insights that can aid the Commission's determination of whether to adopt, and how to structure the procurement criteria, for a demand response auction as a permanent procurement mechanism. The budget we adopt should reflect the minimum budget level sufficient to support these goals and not contravene D.17-04-045. This Decision finds that ORA's recommended $13.5 million budget cap is reasonable in that it most effectively supports these objectives and does not effectuate a doubling of the budget initially authorized for the third Pilot auction. Accordingly, we authorize a total budget for the additional demand response

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[92] SCE Opening Comments to D.17-04-045, July 6, 2017, at 3-4.

[93] Joint Demand Response Parties Opening Comments to D.17-04-045, July 6, 2017 at 5.

[94] ORA Opening Comments to D.17-04-045, July 6, 2017 at 4-5

[95] D.17-04-045 at 13.

auction for deliveries in 2019 of $6 million each for PG&E and SCE and $1.5 million for SDG&E.

Regarding procurement guidelines, OhmConnect and the Joint Demand Response parties argue for maintaining the guidelines adopted in Ordering Paragraph 8 of Resolution E-4817 for the third Pilot auction, which directs the Utilities to procure resources up to their approved budget limit or to a point at which there is a clear price outlier. OhmConnect notes that the procurement methodology adopted in Resolution E-4817 worked well and cites the Independent Expert report opining that the general methodology used by the Utilities in evaluating offers is reasonable for this type of product.[96] The Joint Demand Response Parties note that procurement guidelines similar to those adopted in Resolution E-4817 have been used in the prior Pilots and have caused increasing amounts of cost-effective demand response to be procured, and support their continued use until the full Pilot evaluation is complete.[97] SDG&E supports using these procurement guidelines up to its proposed budgetary limit of $500,000.[98] In comments to D.17-04-045, ORA supports using the procurement guidelines adopted in Ordering Paragraph 21 of D.16-06-029 prior to its modification by D.17-04-045 and also proposes that the Commission "test the effectiveness" of stricter guidelines than those adopted in Resolution E-4817 and require that all winning bids be cost-effective.[99] In comments to the alternate proposed decision, however, ORA recommends that an additional auction

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96 OhmConnect Opening Comments to D.17-04-045, July 6, 2017 at 4.

97 Joint Demand Response Parties Opening Comments to D.17-04-045, July 6, 2017 at 6-7.

98 SDG&E Comments to D.17-04-045, July 6, 2017 at 4.

99 ORA Opening Comments to D.17-04-045, July 6, 2017 at 5.

should utilize the procurement guidelines adopted in D.16-09-059 Ordering Paragraphs 12(a), (c), and (d), including the requirement for Utilities to offer contracts, within the budget limits, to all complying bids up to the simple average August capacity bidding price rather than a clear price outlier in bids.[100] PG&E objects that the "clear price outliers" limitation does not require offers to be competitive with external benchmarks.[101] SCE supports consideration of portfolio needs in selecting bids but also identified advantages to the "budget limit" approach so long as the budget is relatively restricted compared to perceived supply.[102]

We are persuaded to adopt the suggestion ORA presented in comments to the alternate proposed decision. This Decision finds that it is reasonable to continue to utilize the procurement guidelines adopted in Resolution E-4817, which are similar to those used in the prior demand response auction mechanism solicitations, as amended to reflect the inclusion of the procurement selection criteria in Ordering Paragraph 12 (a), (c), and (d) of D.16-09-056. ORA and the Joint Demand Response Parties assert that testing these additional procurement guidelines will not cause delay in conducting an additional 2018 auction.[103] While the direction given in Resolution E-4817 to procure up to the budget cap or a point in which there is a clear price outlier has provided a reasonable approach

[100] ORA Opening Comments to Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 2, 6-8.

[101] PG&E Opening Comments to D.17-04-045, July 6, 2017 at 5.

[102] SCE Opening Comments to D.17-04-045, July 6, 2017 at 5.

[103] ORA Opening Comments to Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 7; Joint Demand Response Parties Reply Comments on Alternate Proposed Decision, October 10, 2017 at 3.

in previous Pilots, modifying the bid selection criteria to require offers for contracts for bids up to the average august capacity price or the budget cap adopted here will balance Commission needs for timeliness and sufficient oversight with a useful test of these criteria that can aid in the Commission's consideration the appropriate procurement criteria if the demand response auction is adopted as a permanent mechanism.[104]

Parties also commented on the Commission's question in D.17-04-045 of whether to include specific procurement criteria for bids located in local transmission constrained areas, or bids that could defer investments in generation, transmission, or distribution. No party affirmatively supports the Commission's adoption of either procurement criteria. The Joint Demand Response Parties note that current guidelines already allow bidders to offer products in locally constrained areas,[105] and oppose using an additional solicitation to select grid investment deferral products.[106] SCE and PG&E contend that local capacity area bids should not be a requirement and that the utilization of Least-Cost, Best-Fit evaluation principles maximizes this value.[107] SDG&E and PG&E argue that deferral of transmission and distribution investments is appropriate in other proceedings but not for the Pilot auction.[108] SCE points out that valuing demand response products for grid deferral would

104 Resolution E-4817, Finding 14.

105 Joint Demand Response Parties Opening Comments to D.17-04-045, July 6, 2017 at 7.

106 Joint Demand Response Parties Reply Comments to D.17-04-045, July 17, 2017 at 3.

107 PG&E Reply Comments to D.17-04-045, July 17, 2017 at 7, SCE Opening Comments to D.17-04-045, July 6, 2017 at 6.

108 PG&E Reply Comments to D.17-04-045, July 17, 2017 at 7; SDG&E Opening Comments to D.17-04-045, July 6, 2017, at 8.

require extensive changes to the auction protocols and pro-forma contract, would add great complexity, and would not further existing goals for the demand response auction mechanism.[109] OhmConnect argues that the Commission could incentivize bids in locally-constrained areas and that bidders should receive information from each utility on the incremental value of local resource adequacy over system.[110] OhmConnect also asserts that valuing distribution upgrade deferral services is a relatively new concept for demand response resources and there is little public information available.[111] PG&E notes that schedule limitations would require the Utilities to keep a significant portion of the 2018-2019 Pilot in place, including the same purchase agreement, because there is insufficient time to reconvene the auction working group to meet a schedule comparable to that utilized in 2017.[112]

This Decision finds that because no party advocated for adopting procurement criteria that bids are for local capacity or to defer transmission, distribution, or generation investments, it is not reasonable to require them in the additional auction. Further, we acknowledge the Utilities' concern that incorporating such requirements would add complexity and may necessitate modifying the auction protocols and pro-forma contracts, and we are persuaded that such substantial changes to the auction design is impractical given the timeline necessary for timely completion for 2019 deliveries. Nevertheless, as we further detailed below, the results of the Potential Study indicate a higher future

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109 SCE Opening Comments to D.17-04-045, July 6, 2017, at 6.

110 OhmConnect Opening Comments to D.17-04-045, July 6, 2017 at 5.

111 OhmConnect Opening Comments to D.17-04-045, July 6, 2017 at 5.

112 PG&E Reply Comments to D.17-04-045, July 17, 2017 at 4.

value for traditional load shed demand response as local capacity rather than as system capacity.[113] We also agree with OhmConnect that it would be useful for Utilities to signal the value or need for local and/or flexible capacity products. We therefore direct the Utilities to prioritize bids for local resource adequacy capacity contracts, where appropriate, over bids for system resource adequacy. To do this, the Utilities shall continue to use the previously approved evaluation criteria but shall work with Energy Division staff to ensure that the capacity values utilized in the bid selection criteria appropriately reflect the value differentials between local and system resource adequacy capacity, or a similar approach. The Utilities shall also indicate to demand response providers the relative value of local or flexible resource adequacy relative to system resource adequacy, to the extent possible within limitations imposed by Commission directions that recognize utility-specific confidential valuation information.[114] Our decision today does not prejudge or preclude alternative future determinations on these issues, including if the Commission authorizes a permanent demand response auction mechanism.

Parties suggest a number of other changes to the auction design and protocols for an additional 2018 solicitation, which we decline to adopt today. OhmConnect asks for megawatt procurement targets rather than continuing to use a budget target.[115] PG&E and SCE propose additional parameter changes

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113 Potential Study at 1-8 through 1-11, 5-27 – 5-28. Shed resources provide the conventional form of demand response by which load is reduced to lower peak demands in the grid.

114 Internal, proprietary resource adequacy values may be used for bid selection. (*See* Resolution E-4802, Finding of Fact No. 8.)

115 OhmConnect Opening Comments to D.17-04-045, July 6, 2017 at 2-3. Joint Demand Response Parties Opening Comments to D.17-04-045, July 6, 2017 at 5.

such as directing utilities to use Least-Cost, Best-Fit evaluation criteria,[116] and requiring Reliability Demand Response Resource products to provide economic bids in CAISO's Day-Ahead market.[117] SDG&E propose accepting bids only from demand response providers who do not currently have Pilot contracts and increasing the 20 percent residential set-aside,[118] while PG&E argues for reducing the residential requirement and qualitative solicitation criteria that value the prior experience of bidders and increase or maintain the number of providers.[119]

We appreciate that parties have presented a range of additional approaches to alter and improve the 2017 auction design and protocols for a 2018 solicitation, but with the specific exceptions identified in this Decision, we are not persuaded that additional changes are warranted at this time to achieve the aims we have identified for the additional auction: ensuring sufficient demand response growth opportunities for third party providers and gaining additional insights into the evolving state of the market, including consolidation or other factors. We are also persuaded by PG&E's arguments that a change such as moving to a megawatt procurement target would require significant changes in auction design and is impractical given timing considerations. This Decision finds that it is reasonable to deny proposed alterations to the auction design, protocols and pro forma contract utilized for the 2017 auction, except that the Utilities shall offer contracts to all complying bids up to the simple average

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116 PG&E Opening Comments to D.17-04-045, July 6, 2017 at 4; SCE Opening Comments to D.17-04-045, July 6, 2017 at 4.

117 SCE Opening Comments to D.17-04-045, July 6, 2017 at 7.

118 SDG&E Opening Comments to D.17-04-045, July 6, 2017 at 2.

119 PG&E Opening Comments to D.17-04-045, July 6, 2017 at 6.

August capacity bidding price or their budget cap, whichever comes first. The Utilities shall also consult with Energy Division staff on any questions that arise in the course of applying these bid selection criteria. Again, this Decision does not prejudge or preclude future alternative approaches to a demand response auction procurement parameters or criteria.

Finally, in responding to the questions posed in D.17-04-045, both PG&E and SCE point to a need for Commission authorization for new cost recovery as there are no current mechanisms available to recover the budget for a 2018 Pilot auction for 2019 deliveries.[120] This Decision authorizes a budget of $13.5 million and directs the Utilities to use the same cost recovery mechanism as that used for the auction approved in Decision 16-06-029 of this proceeding. We are also persuaded by comments to the alternate proposed decision that an additional pilot auction should and can be completed more quickly than the 2017 pilot auction in order to ensure that the additional pilot auction results can inform Energy Division Staff's evaluation of the Pilot.[121] To allow the additional auction to occur in a timely fashion and inform the Energy Division staff's report, we direct the Utilities to release a Request for Offers (RFO) for the additional auction in 2018 for contracts with a one year delivery term in 2019 by no later than February 1, 2018. The Utilities shall submit their advice letters for approval of the auction results no later than May 1, 2018 and adhere to a bid submission

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[120] PG&E Opening Comments on Questions to D.17-04-045, July 6, 2017 at 4 and SCE Reply Comments on Questions from D.17-04-045, July 17, 2017 at 2.

[121] ORA's Opening Comments on Proposed Decision and Alternate Proposed Decision, October 5, 2017 at 9; OhmConnect, Electric Motor Werks, and Stem Joint Reply Comments on the Proposed Decision and Alternate Proposed Decision, October 10, 2017 at 5.

timeline roughly equal to that authorized in Resolution E-4817.[122] The Utilities shall include their final auction timeline in RFO materials for the additional third Pilot auction.

2.3. Next Steps for Demand Response: Resolving Barriers to CAISO Integration and Developing New Models of Demand Response

As further described below, this Decision establishes two new working groups, the Supply Side Working Group and the Load Shift Working Group,[123] and creates a set of tasks for each. The Supply Side Working Group will develop and refine implementable proposals, for the Commission's consideration, to address certain remaining barriers to integrating demand response into the CAISO market. The Load Shift Working Group will develop proposals for specific foundational elements of new models of demand response necessary before launching new models. The Supply Side Working Group is responsible for accomplishing the tasks as described below and providing quarterly status reports to the service list. The Utilities, on behalf of the Load Shift Working Group, shall develop a report on its proposals, which will inform a new rulemaking for developing new models of demand response. Nothing in this

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[122] Resolution E-4817, approved January 19, 2018 In comments to the alternate proposed decision, ORA recommended modifying the name of the working group tasked with addressing new models of demand response. ORA suggested the name, Load Shift, instead of Load Consumption, to better align with the load shift recommendations in the Potential Study. (*See* ORA Opening Comments to Proposed Decision, October 5, 2017 at 4-5.at 47.)

[123] In comments to the alternate proposed decision, ORA recommended modifying the name of the working group tasked with addressing new models of demand response. ORA suggested the name, Load Shift, instead of Load Consumption, to better align with the load shift recommendations in the Potential Study. (*See* ORA Opening Comments to Proposed Decision, October 5, 2017 at 4-5.)

Decision proscribes the Commission from opening a new rulemaking prior to either working group completing the tasks described herein.

Rulemaking 13-09-011 remains open solely to address a pending application for rehearing; the issues in phases one through three have been addressed and the issue of new models of demand response are not ripe at this time but will be addressed in the future rulemaking.

2.3.1. Barriers to Integration and New Models of Demand Response Background

D.16-09-056 explained that the results of the Potential Study would be submitted in two phases with the second phase, focused on newer models of demand response, to be delivered in October 2016. D.16-09-056 also anticipated that a decision focused on new and advanced demand response programs would be developed following the issuance of the second phase of the Potential Study.

The second phase of the Potential Study was issued in March 2017. Prior to its issuance, the Consultants provided a draft report to parties on November 14, 2016, which was followed by a workshop on November 30, 2016. A subsequent webinar on December 9, 2016 gave parties an additional opportunity to ask technical questions about the Potential Study. A December 15, 2016 Ruling posed several questions to parties regarding the results of the draft report of the Potential Study and the recommendations for new models of demand response. Parties filed responses to the questions on January 16, 2017 and reply comments to those responses on January 31, 2017. The results of the second phase of the Potential Study indicate that, with the increased use of renewable generation and mandates to meet a 50 percent renewables by 2030, the potential value for traditional peak-shedding system demand response will be reduced.[124] The Potential Study results conclude that there are opportunities for shed demand response to provide value to the grid as local capacity,[125] but suggest that in place of system shed there will be a necessity to focus on local and distribution system needs and advanced demand response products that can either shift load from times of high demand to times when there is a surplus of renewable generation, or can use loads to dynamically adjust demand on the system at timescales ranging from seconds up to an hour.[126]

Prior to the release of the Potential Study, a workshop was held to discuss demand response program outcomes from 2016. During this workshop, parties addressed the concerns regarding remaining barriers to CAISO integration. Parties developed the following list of remaining barriers:

- CAISO Settlement;
- Click-Through Process;
- Mismatched Supply Plans;
- Incorporating or valuing unintegrated demand response megawatts;
- Changes to Commission and CAISO baselines;
- Resource adequacy issues; and
- Improved wholesale market participant (Community Choice Aggregators/Load Serving Entities) education.

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[124] Potential Study at 1-8. 5-27. Shed resources provide the conventional form of demand response by which load is reduced to lower peak demands in the grid.

[125] *Id*. at 5-28.

[126] *Id*. at 1-1 through 1-11.

During a workshop on April 4, 2017, parties continued to discuss CAISO integration barriers, further explored the results of the Potential Study, and identified policy issues surrounding new models of demand response including: barriers to adoption of new demand response models, the role of the demand response Potential Study, and the current and future coordination needs among proceedings that address various issues related to demand response.

On May 22, 2017, a Ruling was issued asking parties to respond to questions regarding the steps to be taken before launching new models of demand response. The Ruling referenced the list of barriers from the February workshop as well as the following list of activities that the parties recommend the Commission should accomplish before launching new models of demand response:

1. The Commission should undertake several activities related to the resource adequacy proceeding including:
    a) Identification of the value of new products and determination of customer appeal;
    b) Consideration of a policy that pays capacity value for ramping;
    c) Resolution of local resource adequacy requirements for demand response; and,
    d) Review of qualifying capacity requirement for weather-sensitive demand response.
2. Define and develop new products including both load consumption and bi-directional products.

3. Resolve dual-participation issues including defining and addressing barriers.
4. Align retail and wholesale baselines and diversify the baselines by customer and load.
5. Coordinate the efforts of CAISO and the Commission to integrate demand response into the CAISO market, including new models of demand response.
6. Create and implement more accurate dynamic price signals tied to wholesale pricing.
7. Define and clarify jurisdiction regarding Community Choice Aggregation.
8. Consider and adopt consistent time-of-use periods with demand response and rate design.
9. Resolve remaining issues with CAISO integration of Shed demand response.
10. Develop characteristics and values of demand response for distribution system.
11. Develop and define data access rules to enable new demand response models.
12. Consider multi-year procurement demand response contracts.

The CAISO, CESA, CLECA, California Solar Energy Institute Association, Joint Demand Response Parties, NRG, OhmConnect, ORA, PG&E, SDG&E, SCE and Tesla responded to the questions in the Ruling.

2.3.2. Establishment of Supply Side Working Group and Load Shift Working Group

This Decision establishes two working groups, the Supply Side Working Group and the Load Shift Working Group, and assigns a task list for each, as described herein. The purpose of the Supply Side Working Group is to address specific remaining barriers to integrating demand response into the CAISO market. The barriers to be resolved are compiled from those barriers identified in the February 2017 and April 4, 2017 workshops and additional barriers identified in the responses to the May 22, 2017 Ruling. The compiled list of barriers to be resolved by the Supply Side Working Group is presented in Table 1 below. The purpose of the Load Shift Working Group is to develop a proposal for foundational elements of new models of demand response. The Load Shift Working Group should accomplish the tasks as indicated in Table 2 below.

In addition to addressing the tasks, both working groups shall provide the parties to this proceeding with status reports. On a quarterly basis, beginning on January 15, 2018, the Utilities, on behalf of the Supply Side Working Group and Load Shift Working Group, shall serve a status report to the service list in this proceeding describing the activities of each group and the tasks accomplished. The Utilities shall include in the status reports details of discussion and outputs of the working group, reflecting both consensus items and points of conflict. No later than January 31, 2019, the Utilities, on behalf of the Load Shift Working Group, shall serve a final report to include proposals on its assigned tasks. The final report shall include the same details required in the status reports. The final report will inform the future rulemaking to consider the development of new models of demand response.

In comments to the alternate proposed decision and the proposed decision, the Joint Demand Response Parties point to the ambitious schedule for the two working groups and request the Commission consider the impact on parties.[127] The Commission encourages party participation in these working groups and, therefore, directs the Utilities, in consultation with the

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[127] Joint Demand Response Opening Comments on Proposed Decision, October 5, 2017 at 12-13.

Energy Division, to establish schedules for the two working groups that do not overlap or conflict with demand response activities, to the extent possible.

2.3.2.1. Supply Side Working Group Tasks Addressing Barriers to Integration

Over the course of two workshops, parties identified several remaining barriers to CAISO integration. This Decision recognizes that these barriers continue to exist. In comments, the CAISO states that the seven items identified during the February 2017 workshop are barriers to *further* integrating demand response into the CAISO market and highlights that significant amounts of demand response are already integrated and functioning.[128] This Decision determines that the Commission should adopt approaches to combatting the specific barriers addressed in the February and April 2017 workshops as well as those discussed in comments. This Decision assigns the Supply Side Working Group the task of developing proposals to resolve several of these barriers, as further discussed below. Acknowledging that certain barriers are currently being considered in other proceedings, this Decision also examines these barriers to ensure any necessary coordination between proceedings.

This Decision begins with the issue of CAISO settlements, which is considered to be a top priority by the CAISO, Joint Demand Response Parties, PG&E, and Southern California Edison. Explaining that all issues identified in a comprehensive review of 2015-2016 market activities have been corrected, the CAISO claims that "corrected settlements will occur at the next available settlement recalculation" and all corrected trades will be resettled by

[128] CAISO Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 1.

October 2017.[129] No party contested this statement. Those identifying this issue as a priority convey that using the current CAISO stakeholder process is the best approach to addressing this issue.

Because the settlement issue should be resolved by October 2017, this Decision takes no action on this issue and considers the CAISO stakeholder process to be the appropriate venue to complete its resolution. However, to ensure the Commission is kept abreast of any remaining or new issues related to settlements, the Supply Side Working Group's quarterly status report shall include a brief overview of all activities related to CAISO settlements.

Several parties suggest that resource adequacy issues should be near the top of the Commission's priority list of barriers to address.[130] Parties expanded upon the issue of resource adequacy in comments to the May 22, 2017 Ruling and specified the following specific issues: the resolution of local resource adequacy requirement for demand response, qualifying capacity requirements for weather-sensitive demand response, and multi-year procurement demand response contracts. Several parties state that resource adequacy issues should be addressed in the resource adequacy proceeding.[131] CLECA contends that some

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129 *Id.* At 2.

130 CAISO Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 1, CLECA Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 8, NRG Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 3, PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2-3, SDG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2, and SCE Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2-3.

131 CAISO Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 4-6, CLECA Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 13; Joint Demand Response Parties Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 10; NRG Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2 and 6, ORA Opening Comments on Remaining Barriers and New Models,

Footnote continued on next page

resource adequacy issues, *i.e.,* weather sensitive qualifying capacity, may require action by the CAISO and cannot be resolved in terms of the resource adequacy proceeding alone.[132] However, PG&E underscores that D.17-06-027 calls for the establishment of several working groups including one for weather-sensitive demand response.[133] Throughout the life of this proceeding, the Commission has stated that resource adequacy policies will be determined in the resource adequacy rulemaking. This Decision finds that the issues of the resolution of local resource adequacy requirement for demand response, qualifying capacity requirements for weather-sensitive demand response, and multi-year procurement demand response contracts are more appropriately addressed in the resource adequacy proceeding. However, for the purposes of transparency and coordination efforts, the Supply Side Working Group should provide updates on the resource adequacy efforts through the quarterly reports. This task will be added to the Supply Side Working Group Task List in Table 1 below.

In regard to the issue of baselines, parties discussed an existing stakeholder process, the CAISO's Energy Storage and Distributed Energy Resources (ESDER II), but note that a separate Commission process and decision must take place to incorporate baseline changes into the Commission's retail programs.[134] The CAISO received approval from its Board of Governors on

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July 6, 2017 at 4, PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 11; SDG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2 and 6; and SCE Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2 and 9.

[132] CLECA Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 13.

[133] PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 11.

[134] Joint Demand Response Parties Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2.

July 26, 2017 to file new demand response settlement baselines (developed through the ESDER II) with the Federal Energy Regulatory Commission (FERC).[135] The CAISO recommends the Commission explore whether and how utility demand response program baselines should align with the expanded CAISO baseline options available if and when approved by the FERC.[136] This issue is in the scope of the current demand response portfolio applications for 2018-2022, Application (A.) 17-01-012 et al. As such, the issue of adopting revised baselines should be considered in that proceeding. Following adoption of the wholesale baselines, the Utilities shall file a copy of the FERC tariff in A.17-01-012 et al. for consideration in that proceeding.

Parties addressed several CAISO technical requirements that continue to create barriers to integration. The Utilities and the Joint Demand Response Parties maintain that the issue of incorporating or valuing un-integrated demand response megawatts should be a medium to high-priority issue for the Commission.[137] PG&E explains that there are CAISO requirements that preclude certain customers from being included in a resource and while these requirements do not prevent integration, it may result in less megawatts being

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135 CAISO Opening Comments on Proposed Decision, October 5, 2017 at 3. The comments update the information provided in July 6, 2017 comment indicating the CAISO will seek approval from its Board of Governors to file new settlement baselines.

136 CAISO Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 3.

137 Joint Demand Response Parties Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2; PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2-3, SDG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2, and SCE Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2.

integrated.[138] Contending that the barrier is related to CAISO requirements, PG&E recommends a different process for each of the three specific barriers it identifies: 1) a stakeholder process at the CAISO to address minimum size requirements; 2) a stakeholder proposal to the CAISO to require new market participants to register in order to address the problem of load serving entities not registered; and 3) a Commission-facilitated working group to investigate less costly technologies to address the expensive telemetry requirement for resources greater than 10 megawatts.[139]

In comments to the alternate proposed decision and proposed decision, the CAISO takes issue with the assertion that these barriers are solely related to CAISO requirements. The CAISO states there is shared responsibility for the existence of these barriers. Contending the Utilities should bear some responsibility for these barriers, the CAISO surmises that the Utilities are either unable or unwilling to combine multiple and distinct programs into single CAISO proxy demand response resources to meet minimum resource size requirements. SCE considers CAISO's proposal to combine utility programs into one resource imprudent and impractical and ignores operational and regulatory hurdles.[140] Highlighting that SCE has attempted to refine its programs based on the CAISO tariff where necessary, SCE states that the CAISO proposal underestimates the dynamic nature and retail structure of the demand response portfolio and its underlying customer types.[141]

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138 PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2-3.

139 *Ibid*.

140 SCE Reply Comments to Proposed Decision, October 10, 2017 at 3.

141 *Ibid*.

PG&E, CLECA and SCE identify several additional technical barriers to CAISO integration including uncertainties over minimum run times, maximum run hours, partial de-rate options, reliability demand response resource day ahead bidding options, the need for additional resource parameters on CAISO Resource Data Templates, and others.[142] The Joint Demand Response Parties suggest a working group to address and resolve the issues. SCE recommends a new phase of the proceeding to identify issues and proposals, along with workshops.

As highlighted by PG&E, these technical barriers relate, in part, to CAISO requirements and therefore should be resolved through a CAISO-led working group. Because integrating demand response into the CAISO market is a high priority to the Commission, a Commission-facilitated working group is appropriate. The Supply Side Working Group is assigned the task of working with the CAISO to address the three barriers as stated by PG&E above, the additional technical barriers identified above, and others the working group identifies. The required quarterly reports shall include a status report on efforts to resolve these technical barriers. We note that these issues are not new and, therefore, do not require a new phase of this proceeding as recommended by SCE. Furthermore, this Decision reiterates that assigning the working group the task of addressing these issues in no way indicates a change in Commission policy established in D.15-11-042, whereby the Utilities shall only attribute capacity value to demand response programs that are integrated into the CAISO

[142] CLECA Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2-7. PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 3, and SCE Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2.

wholesale market or embedded in the California Energy Commission's unmanaged/base case load forecast.

In addition to the technical barriers previously discussed, parties contend that dual participation rules also create barriers to integration. Dual participation issues are of two varieties: CAISO-related and Commission-related. For dual participation issues needing a CAISO determination, *i.e.,* each registration in the CAISO can only have one scheduling coordinator, and that no location can be registered to both a reliability demand response resource and a proxy demand resource for the same trading day,[143] the CAISO has a stakeholder process in place. Interested persons may use the Supply Side Working Group to develop demand response related recommendations to take to the CAISO stakeholder process. The quarterly report shall include a brief overview of these efforts. The other variety of dual participation issues falls under the Commission's jurisdiction and involves fairness, *i.e.,* comparable dual participation rules for utility-administered demand response programs and third-party demand response programs. This issue is currently in scope in the demand response application proceeding, A.17-01-012 et al., and should be considered within that proceeding.

The issue of mismatched supply plans has not been thoroughly defined in the record of this proceeding. In comments, the Joint Demand Response Parties, PG&E, and SCE raise this issue as a priority.[144] PG&E contends the timing of

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143 CAISO Tariff Section 4.5.1.1.3 and Section 4.13.2. The CAISO also prohibits any registration from having more than one load serving entity.

144 Joint Demand Response Parties Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2, PG&E Opening Comments on Remaining Barriers and New Models,

Footnote continued on next page

supply plans for resource adequacy valuation impacts demand response providers, their scheduling coordinators and load serving entities. Furthermore, PG&E cautions that the increase of non-utility providers such as Community Choice Aggregators will lead to more mismatched supply plans.[145] Joint Demand Response Parties recommend a "working group process be initiated to address which plans govern and the applicable dispute resolution process."[146] SCE recommends a CAISO stakeholder process while PG&E suggests a Commission-led working group to inform the resource adequacy proceeding. This Decision determines that it is appropriate to assign the Supply Side Working Group to address this barrier. The working group should further define this barrier and develop proposals to be make available to the CAISO stakeholder process and resource adequacy proceeding.

Joint Demand Response Parties, PG&E and SCE consider the issue of the Click-Through Process authorization to be a priority for the Commission. Joint Demand Response Parties and SCE recommend that the issue be addressed through a working group process, while PG&E suggests continuing the use of the ongoing Rule 24 proceeding. The Rule 24 proceeding is not an active proceeding: the initial policies were adopted in R.07-01-041, which was closed in 2012, and the Commission considered rate recovery for implementing Rule 24 in A.14-06-001et al., which has also been closed. Furthermore, several advice letters were filed on January 3, 2017 requesting approval for implementation of the

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July 6, 2017 at 2, and SCE Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 3.

145 PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2.

146 Joint Demand Response Parties Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 2.

click-through process; these have been approved by the Commission through Resolution E-4868, which ordered additional implementation processes, Advice Letter filings, and the filing of an application. Hence, this Decision finds the issue of the Click-Through process authorization will be addressed through these procedural venues and does not need to be addressed by the Supply Side Working Group.

Only three parties address the issue of improving wholesale market participant education. Joint Demand Response Parties suggests a joint CAISO and Commission working group be initiated to address needed improvements. OhmConnect recommends the CAISO develop an issue paper and hold a workshop on this issue. This issue overlaps with the issue of new market participant registration addressed above. As previously stated in this Decision, the issues regarding market participants relates to CAISO requirements and should be addressed through a CAISO led working group. However, because integrating demand response into the CAISO market is a high priority to the Commission, a Commission-facilitated working group is also appropriate. Hence, we add this issue to the task list for the Supply Side Working Group. The quarterly reports shall include an overview of the activity, any action taken by the CAISO, any need for Commission consideration, and any resolution.

During the workshops and/or in response to the May 22, 2017 Ruling, parties discussed activities related to demand response: a) dynamic pricing signals, b) Community Choice Aggregator and direct access provider issues; c) time-of-use issues; and d) demand response for distribution system. As further explained below, the Commission is either currently exploring or plans to explore these activities in other proceedings.

The Utilities, Joint Demand Response Parties, and CLECA each address whether to pilot dynamic pricing signals, with PG&E, SCE, and the Joint Demand Response Parties stating that this issue could be addressed in general rate cases, rate design windows, or R.14-08-013 (the Distribution Resources Plan proceeding).[147] CLECA contends there is not obvious venue for such a pilot and suggests holding a workshop.[148] SDG&E maintains they already have multiple rates to provide dynamic price signals to customers but suggest that dynamic price signals tie to wholesale pricing for Community Choice Aggregators and direct access providers could be piloted in this proceeding.[149] This Decision determines that creating and implementing more accurate dynamic pricing signals should be addressed in utilities' general rate cases and/or rate design windows in order to ensure that the signals are part of rate design.

With respect to issues specific to Community Choice Aggregators and direct access providers, SDG&E contends the Commission should consider these issues in R.13-09-011.[150] The Commission recently opened one rulemaking to address modifications to the Power Charge Indifference Amount and is considering whether to open an additional rulemaking on policies for Community Choice Aggregator and direct access providers. Issues related to

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[147] Joint Demand Response Parties Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 10, PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 12, and SCE Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 10.

[148] CLECA Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 14.

[149] SDG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 7.

[150] *Ibid.*

Community Choice Aggregator or direct access providers may be more appropriately addressed in a future rulemaking.

Similar to dynamic pricing pilots, the Utilities suggest that the consideration and adoption of consistent time-of-use periods should be addressed in the general rate cases or rate design window proceedings.[151] Furthermore, SCE describes several current time-of-use activities and contends that introducing a new proceeding to address Shift and Shed rate structures would only complicate matters.[152] Because time-of-use periods are currently being addressed in general rate cases and rate design windows, it would be duplicative to address the same issues in this proceeding. Furthermore, coordination efforts between two or, even, three proceedings could further complicate achieving consistency. Hence, this Decision finds that the most appropriate place to consider consistent time-of-use periods is in the general rate cases and rate design window proceedings. The development of characteristics and values of demand response for distribution system is currently being addressed in the Integrated Distributed Energy Resources and Distribution Resources Plan proceedings and will not be addressed in this proceeding.[153]

2.3.2.2. Load Shift Working Group Tasks

This Decision now turns to the activities that parties identified as related to new models of demand response, which include: identify the value of new

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[151] PG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 12-13, SDG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 7, and SCE Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 10-11.

[152] SDG&E Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 11.

[153] R.1410003, Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, September 1, 2016 at 3-4.

products and determination of customer appeal; consider a policy that pays capacity value for ramping; define and develop new products;[154] coordinate the efforts of CAISO and the Commission to integrate new models of demand response into the CAISO market; and develop and define data access rules to enable new demand response models. This Decision recognizes that the Commission must undertake several activities before launching new models of demand response but should move forward on the development of these foundational elements. The Load Shift Working Group is hereby established and is tasked with developing proposals for each of these foundational activities. To ensure transparency, the Load Shift Working Group shall serve quarterly reports on the status of the group's work. A final report including all of the proposals shall be served no later than January 31, 2019 and may inform a future rulemaking on new models of demand response. The working group is not expected to resolve every issue thoroughly. Rather, the working group is tasked with developing a proposal for a foundation that the Commission can use to inform the rulemaking to adopt policies and designs for new models of demand response. Again, nothing in this Decision precludes the Commission from opening the rulemaking prior to the completion of the Load Shift Working Group's final report.

With respect to the New Models Foundational activities, parties generally agree that working groups are the best approach to addressing these issues, especially the issues of defining and developing new products including load consumption and bi-directional products and coordinating the efforts of CAISO

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[154] Including both load consumption and bi-directional products.

and the Commission to integrate new models into the CAISO market. CALSEIA and TESLA further suggest that an outside facilitator could be valuable for obtaining new perspectives.[155] This Decision sees merit in utilizing an outside facilitator with experience in organizing working groups, in addition to technical experience. PG&E, SDG&E, and SCE are directed to work with the Commission's Energy Division to select a facilitator from a pool of available candidates, drawn in consultation with Energy Division.[156] Load Shift Working Group meetings should begin no later than January 31, 2018. Furthermore, as recommended by several parties, the Load Shift Working Group should coordinate its efforts with CAISO efforts. Finally, Energy Division is designated as having an oversight role in the Load Shift Working Group.

In regard to the identification of the value of new products and consideration of a policy that pays capacity value for ramping, some parties argued that the working group should be in the resource adequacy proceeding. As discussed previously, all resource adequacy-related issues will be determined in the resource adequacy proceeding. However, given the importance of these issues, this Decision finds it appropriate for the Load Shift Working Group to develop a proposal on how to pay a capacity value for load consuming and bi-directional products and include the final proposal in the final working group report but also serve the report to the service list of the resource adequacy proceeding.

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[155] CALSEIA Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 6 and Tesla Opening Comments on Remaining Barriers and New Models, July 6, 2017 at 7.

[156] PG&E and SCE Opening Comments, October 5, 2017 at 12-13.

Parties presented a spectrum of views as to whether the Commission should address the issue of developing and defining data access rules to enable new demand response models in this proceeding or at all. PG&E argues that a framework already exists for third-party providers to obtain customer usage information through the Rule 24 process and the "Share My Data" platform. SDG&E contends that data issues are best addressed in a proceeding that encompasses all distributed energy resources. Joint Demand Response Parties and OhmConnect provide a list of issues that should be addressed. SCE contends that data access may not be an issue that needs to be resolved prior to implementing new models of demand response.

This Decision first finds that the data access issues listed by Joint Demand Response Parties and OhmConnect, including the matter of the click-through process, are already being addressed in other venues and relate to current models of demand response. Furthermore, determinations made regarding data access issues related to new models of demand response in no way impacts implementation of the click-through solutions previously discussed in this Decision.

With respect to new models of demand response, data access should be addressed uniformly across all distributed energy resources and is therefore more appropriately addressed in R.14-08-013, the Distribution Resource Plans proceeding. However, based upon the experience in this proceeding with respect to data access, it is important the Commission pursue the development of a list of potential data access issues that the Commission should consider before implementing new models. Hence, the Load Shift Working Group should identify data access issues to address prior to the launching of new models of demand response. The final set of issues shall be included in the final working group report and also provided to the service list of R.14-08-013.

2.3.2.3. Working Group Tasks

The tasks assigned to the Supply Side Working Group are presented in Table 1 and the tasks assigned to the Load Shift Working Group are presented in Table 2. Quarterly reports shall be served on the service list of R.13-09-011 beginning January 15, 2018 and thereafter on April 15, July 15, October 15, and January 15, until the final report is served on January 31, 2019 for the Load Shift Working Group and June 30, 2019 for the Supply Side Working Group.

TABLE 1 **Supply Side Working Group Tasks**
Provide status reports of CAISO Settlement Issues Addressed in CAISO Stakeholder Meetings.
Provide status report of Resource Adequacy Issues Addressed in Resource Adequacy Proceedings.
Provide status report of work with the CAISO to address technical barriers to integration: i) minimum size requirements, and ii) less expensive telemetry requirements.
Develop proposals to address mismatched supply plans and provide to the CAISO stakeholder process and the resource adequacy proceeding prior to June 30, 2019.
Improve Wholesale Market Participant Education.
Develop proposal to address local resource adequacy, weather-sensitive demand response qualifying capacity requirements, and multi-year procurement contracts. Provide to resource adequacy proceeding prior to June 30, 2019.
Develop stakeholder positions for the CAISO rules impacting dual participation, e.g., one load serving entity per resource to provide to the CAISO.

TABLE 2 Load Shift Working Group Tasks
Development of a proposal that defines new load consumption and bi-directional products.
Development of a proposal of whether and how to pay a capacity value for load consuming and bi-directional products to provide to the resource adequacy proceeding prior to January 31, 2019.
Development of a list of data access issues relevant to new models that should be addressed prior to launching the new models.
Development of a proposal on how to better coordinate the efforts of the CAISO and the Commission to integrate new models of demand response.
Development of a proposal to identify the value of new products to provide to resource adequacy proceeding prior to January 31, 2019.

3. Comments on Proposed Decision

The proposed decision of the ALJs in this matter and the alternate proposed decision of Commissioner Guzman Aceves were mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by California Energy Storage Alliance, CAISO, CLECA, California Solar Energy Industry Association, Direct Access Customer Coalition/Alliance for Retail Energy Markets (DACC/AREM), Joint Demand Response Parties, ORA, Olivine, PG&E, SDG&E, SCE and (jointly) Stem, OhmConnect and Electric MotorWerks on October 5, 2017, and reply comments were filed by DACC/AREM, Joint Demand Response Parties, ORA, PG&E, SDG&E, SCE, and (jointly) Stem, OhmConnect and Electric MotorWerks on October 10, 2017. Clarifications and corrections were made throughout this Decision in response to the comments.

4. Assignment of Proceeding

Martha Guzman Aceves is the assigned Commissioner and Kelly A. Hymes and Nilgun Atamturk are the assigned ALJs in this proceeding.

Findings of Fact

1. The multiple-step process proposed by the Utilities is inefficient and unnecessary.

2. A one-step assessment of whether a Competing Provider's demand response program is similar provides the necessary transparency required by the demand response principles and is efficient.

3. The definition of a similar program is determined in this Decision.

4. The Utilities and other interested persons will be afforded an opportunity to be heard by submitting written input in the Advice Letter process.

5. The Commission will have the final determination of the Competing Provider's Advice Letter through a Tier Three process.

6. Using a Tier Three Advice Letter process balances expediency, transparency, and the appropriate level of regulatory oversight.

7. Defining the customer type and providing the approximate number of customers to whom the demand response program is marketed in the Tier Three Advice Letter will allow the Commission to ensure that a large group of customers are not omitted from demand response opportunities.

8. With respect to determining whether a program is similar, it is possible that more or less stringent regulatory oversight of the process may be needed in the future.

9. A similar program requires that the customer type and approximate number of customers marketed to are alike in substance or essentials.

10. All parties agree that the Competing Provider should designate the demand response resource type of the proposed demand response program.

11. It is redundant to require a similar demand response program to adhere to the same environmental requirements in Public Utilities Code Section 454.52.

12. Requiring resource adequacy reporting for determining whether a demand response program is similar is redundant to reporting efforts in the resource adequacy proceeding.

13. If a Competing Provider does not seek resource adequacy credit for its similar demand response program, the Commission cannot determine the overall state load impacts of demand response programs.

14. The Commission has determined that fossil-fueled back-up generation is antithetical to the efforts of the Commission's Energy Action Plan and the Loading Order.

15. It is fair to require a Competing Provider to comply with the Prohibited Resource Policy since the Competing Utility must comply with the policy.

16. The Commission adopted a demand response principle to protect customer choice.

17. The Commission wants to ensure that third-party entities (*e.g.,* demand response providers and aggregators) have a level playing field in order to increase customer choice and competition.

18. Requiring the Competing Provider to include, in its Advice Letter, the name of the Competing Utility, the Competing Utility's demand response program(s) similar to the Competing Provider's proposed program, and an explanation of how the program's similarities comply with this Decision should accelerate the staff analysis of the Advice Letter and lead to an expedient regulatory process.

19. The Competitive Neutrality Cost Causation implementation time begins with the determination of whether a proposed program is similar.

20. Affected customers are defined as the Competing Provider's customers to whom the Competing Provider will market the demand response program deemed similar.

21. The required 30-day letter in Step Three of the implementation process should assist in customer education of the implementation process and alleviate customer confusion of the bill credit.

22. The Commission is embarking on new territory with the implementation of the Competitive Neutrality Cost Causation Principle.

23. It is prudent to review the implementation process to ensure the process and the principle are achieving the intent of the Commission.

24. All source solicitations conducted in 2014 and 2016 do not provide current business opportunities to grow third party demand response in 2019.

25. Utility programs that remain available to demand response aggregators have not been shown as resulting in an overall growth of business opportunities for third party demand response providers in 2019.

26. Utility demand response programs available to third party providers, distributed resource pilots, and other all-source solicitations do not further the purposes of the demand response auction Pilot or Commission policy adopted in D.16-09-056.

27. The one-year demand response auction mechanism budget authorized for the third Pilot, divided over two years of contract deliveries resulted in a flattening of growth in capacity procured through the Pilot over the 2018-2019 contract delivery years.

28. Business opportunities for growth in third party-provided demand response in 2019 have been limited.

29. An additional auction for 2019 deliveries can provide further insights into the evolving state of the demand response market, including consolidation.

30. Additional insights can be gained from an auction in 2018 that applies the procurement guidelines for a permanent demand response auction mechanism adopted in D.16-09-056 and can assist the Commission's determination on whether to adopt a demand response auction as a permanent mechanism and whether modifications to auction parameters are needed.

31. It is reasonable and prudent to allow for an additional Pilot auction to supplement the authorized procurement budget for 2019 contracts.

32. The one gigawatt figure adopted by the Commission in D.16-09-056 is not a procurement target.

33. The total 203 megawatts procured by the utilities for 2019 deliveries through the demand response auction mechanism is well below the one gigawatt procurement ceiling adopted in D.16-09-056.

34. An additional demand response auction for 2019 deliveries furthers Pilot goals and is consistent with the parameters and policies adopted in D.16-09-056. The overall Pilot goals are to gain experience in the CAISO market and investigate whether a competitive procurement mechanism for supply side resources outside of traditional utility goals is viable.

35. An additional auction for 2019 deliveries by PG&E, SCE and SDG&E will achieve Pilot goals and aid in Commission's consideration of the merits of the demand response auction mechanism.

36. ORA's proposed budget cap is the minimum level sufficient to support limited objectives for a 2018 auction of growth in third party demand response business opportunities, support for the competitive market, insight into market

consolidation, and the application of the procurement criteria adopted in D.16-09-056.

37. The demand response procurement guidelines utilized in the third auction, modified to require a shorter solicitation and to require the Utilities to offer contracts for bids up to the average August capacity price or the budget cap, whichever comes first, provide a reasonable balance of utility discretion in demand response auction mechanism procurement with Commission needs for timeliness and sufficient oversight.

38. No party supported changing the Pilot auction guidelines to target locally constrained areas or support deferral of transmission and distribution systems.

39. It would be useful for utilities to signal local and flexible capacity needs to demand response providers to the extent possible.

40. Parties presented a range of proposals to modify the 2017 demand response auction mechanism guidelines.

41. Adding procurement criteria related to locally constrained areas and transmission or distribution investment deferral to the 2017 auction mechanism guidelines would entail significant complexity and could delay an additional 2018 auction for deliveries in 2019.

42. Altering the 2017 auction guidelines is unnecessary to achieve the limited objectives of an additional auction for 2019 deliveries.

43. Declining to adopt any particular procurement criterion at this time does not prejudge or preclude alternative Commission determinations on these issues in the future.

44. Barriers to integrating current models of demand response into the CAISO market continue to exist.

45. The barrier of CAISO Settlements is expected to be resolved by October 2017.

46. The CAISO stakeholder process is the appropriate venue to address the CAISO Settlement barrier.

47. The issue of new baselines for demand response is in the scope of the current demand response portfolio applications for 2018-2022.

48. Incorporating or valuing un-integrated demand response megawatts relates to CAISO requirements and should be addressed in a CAISO led working group.

49. The issues of incorporating or valuing un-integrated demand response megawatts are not new issues and do not require a new phase of this proceeding.

50. Assigning a working group the task of addressing these issues in no way indicates a change in Commission policy, whereby the Utilities shall only attribute capacity value to demand response programs that are integrated into the CAISO market or embedded in the California Energy Commission's unmanaged/base case load forecast.

51. The issue of mismatched supply plans requires further definition.

52. The Rule 24 proceeding is not an active proceeding as it was closed in 2012.

53. Application 14-06-001 et al, which addressed rate recovery for implementing Rule 24, is closed.

54. Advice Letters implementing the click-through authorization process were filed on January 3, 2017 and approved by Resolution E-4868.

55. The issue of the click-through process should be closed once a resolution addressing the advice letters is considered by the Commission.

56. The issue of market participant education relates to CAISO requirements and should be addressed through a CAISO stakeholder process.

57. Because integrating demand response into the CAISO market is a high priority to the Commission, it is reasonable to allow a Commission-facilitated working group to address the issue of market participant education.

58. Remaining technical barriers to CAISO market integration should be discussed in the Supply Side Working Group to form recommendations to the CAISO.

59. The Commission should undertake several activities before launching new models of demand response but move forward on developing the foundational elements.

60. The Commission should assign the relevant activities to the Load Shift Working Group to develop proposals on foundation elements that the Commission could use to inform a new rulemaking.

61. In order to ensure that dynamic pricing signals are part of rate design, creating and implementing more accurate signals is best addressed in general rate cases and/or rate design windows proceedings.

62. Time-of-use periods are currently being addressed in general rate cases and rate design windows.

63. It would be duplicative to address time-of-use periods in this proceeding.

64. The development of characteristics and values of demand response for distribution system is being addressed in the Integrated Distributed Energy Resources and Distribution Plan proceedings.

65. The CAISO has a stakeholder process in place for addressing CAISO rules regarding the prohibition of more than one scheduling coordinator and dual registration in a reliability demand response resource and a proxy demand resource.

66. Comparable dual participation rules for utility-administered demand response programs and third-party demand response programs are in the scope of A.17-01-012 et al.

67. Data access issues are being addressed in other regulatory venues or other Commission proceedings.

68. Data access issues should be addressed uniformly across all distributed energy resources and is more appropriately addressed in R.14-08-013.

Conclusions of Law

1. The Commission should adopt a Tier Three Advice Letter Process to determine whether a Competing Provider's demand response program is similar to a Competing Utility's demand response program.

2. The Commission should require that the type of customer and approximate number of customers marketed to in the Competing Provider's program should be similar to the Competing Utility program's customer type and the approximate number of Competing Provider's customers to which the Competing Utility markets its similar demand response program(s).

3. A similar resource type should comport with Commission definitions of load modifying or supply demand response resources.

4. Pub. Util. Code § 454.52 requires all load serving entities to file an integrated resource plan to ensure that the load serving entities meet greenhouse gas emissions reduction targets, procure 50 percent eligible renewable energy resources by 2030, enhance demand-side management and minimize local pollutants.

5. All load serving entities are required to comply with resource adequacy requirements, including reporting.

6. For the purposes of determine the overall state load impacts of demand response programs, it is reasonable to require Competing Providers submit annual demand response load impacts in compliance with the load impact protocols.

7. For the purposes of determining the impact of the Competitive Neutrality Cost Causation Principle's implementation, the Commission should require a Competing Provider to provide ex ante and ex post load impacts.

8. The Commission should require a similar program demonstrate that it will not use a prohibited resource to enable load shed during demand response events.

9. The Commission should require a similar program allow for third-party participation if the competing utility's program also allows for third-party provider's participation.

10. The Commission should require a Competing Provider to include, in its Advice Letter, the name of the Competing Utility, the Competing Utility's demand response program(s) similar to the Competing Provider's proposed program, the Competing Utility's ex-ante load impacts for its program from the previous year's Load Impact Report protocol filing, and an explanation of how the Competing Provider's program similarities comply with this Decision.

11. The Commission should require the use of the bill credit on Competing Provider's customers' bills to end cost recovery of the Competing Utility's similar demand response program.

12. The Commission should require the Utilities to undertake a process, with input from parties, to develop and propose a method to determine the bill credit.

13. The Director of the Commission's Energy Division should be authorized to perform an evaluation of and issue a report on the Competitive Neutrality

Cost Causation Principle's implementation process, including the level of regulatory approval and any unintended consequences.

14. Conducting an additional demand response auction in 2018 for 2019 deliveries can aid in informing a Commission decision on whether to adopt the demand response auction as a permanent procurement mechanism and whether to modify the previously-adopted procurement criteria, and should be exercised.

15. It is reasonable to conduct an additional auction to support the market for competitive demand response during 2018 while the Commission makes a policy determination of whether to adopt a demand response auction as a permanent procurement mechanism.

16. An authorized budget of $13.5 million for the Utilities ($6 million for PG&E and SCE each, and $1.5 million for SDG&E) to procure additional contracts for one year of delivery in 2019 is reasonable and supports the limited objectives for conducting an additional Pilot auction.

17. Utilities should signal local and flexible capacity needs to third party demand response providers to the extent possible and should prioritize bids for local resource adequacy, where appropriate, over bids for system resource adequacy.

18. The 2017 demand response auction mechanism guidelines should be applied without modification to an additional demand response auction for 2019 deliveries, except that contract terms shall be limited to one year, the Utilities should offer contracts in accordance with the bid selection criteria adopted in D.16-09-056 Ordering Paragraph 12, and should complete the additional 2018 auction more quickly than the 2017 auction in order to allow the solicitation results to be incorporated into Energy Division staff's evaluation of the Pilot.

19. The Commission should adopt appropriate approaches to combatting barriers addressed in this Decision before launching new models of demand response.

20. The Commission should establish a Supply Side Working Group to address barriers to the integration of demand response into the CAISO market.

21. Resource adequacy related barriers will be addressed in the resource adequacy proceeding.

22. The issue of adopting revised baselines should be considered in A.17-01-012 et al.

23. The Commission should establish a Load Shift Working Group to develop proposals for foundational elements that the Commission may use to inform a new rulemaking to adopt policies and designs for new models of demand response.

O R D E R

IT IS ORDERED that:

1. The four-step process outlined in Attachment 1 of this Decision is adopted to implement the Commission's Competitive Neutrality Cost Causation Principle.

2. A Community Choice Aggregator or Direct Access Provider's (Competing Provider) proposed demand response program is considered similar to a current demand response program provided by an investor-owned utility (Competing Utility in the overlapping service area (Competing Utility's program) if the Competing Provider's program meets all of the following requirements:

- is offered to the same type of customer (e.g., residential customer) and the approximate number of Competing

Provider's customers to which the Competing Utility markets its similar demand response program;

- is classified as and can be demonstrated to be the same resource, either a load modifying or supply resource, as defined by the Commission;
- can validate that demand response program customers are not receiving load shedding incentives for the use of prohibited resources during demand response events; and
- allows the participation of third-party demand response providers or aggregators, if the Competing Utility's program also allows such third-party participation.

3. Within 90 days of the issuance of this Decision, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall serve, to parties in Rulemaking 13-09-011, a proposed approach for determining the bill credit to end cost recovery of Competing Provider's customers no longer eligible to participate in the similar demand response program and a draft standardized customer letter noticing and explaining the process. No later than 30 days after the proposed approach and letter are served, parties may serve informal comments on the proposed approach and letter.

4. Within 60 days after serving a proposed approach for determining the bill credit to end cost recovery of the Competing Provider's customers, the Director of the Commission's Energy Division is authorized to facilitate a workshop to discuss the proposed approach and develop a consensus. All parties and other interested persons are advised to participate because the final approach will be used by the utilities.

5. Within 30 days after the workshop to discuss the proposed method and develop a consensus proposal, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall work with parties to this proceeding to submit a Tier Three Advice Letter that either

(1) proposes the consensus approach or (2) proposes one of the proposed approach and describes all alternatives.

6. The Director of the Commission's Energy Division is authorized to perform an evaluation of and issue a report on the Competitive Neutrality Cost Causation Principle's implementation process and any unintended consequences. The report should address: (1) the implementation process, including the regulatory approval process, based on information and feedback from Competing Providers (as defined in Attachment 1 of this Decision) on the process adopted in Ordering Paragraph 1; (2) any demand response elements negatively affected by the implementation of the Principle; and (3) recommendations for any changes to address the identified negative impacts. The Competing Provider shall submit all data requested by the Energy Division. The report should be provided to the Commission within 30 months following the adoption of the resolution granting a Competing Provider's demand response program similar status. On an annual basis, every April 1, Competing Providers shall submit to the Director of Energy Division annual load impacts of its similar demand response program in compliance with the load impact protocols.

7. Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company shall conduct an additional demand response auction in 2018 for deliveries in 2019 in accordance with the procurement budget, guidelines and all other parameters adopted herein.

8. The total additional budget authorized for a 2018 solicitation in the demand response auction mechanism pilot is $6 million each for Southern California Edison Company and Pacific Gas and Electric Company and $1.5 million for San Diego Gas & Electric Company.

9. Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company shall recover the costs of the additional 2018 demand response auction mechanism pilot solicitation using the same mechanism as that used for the auction approved in Decision 16-06-029.

10. Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company (the Utilities) shall utilize the final approved 2017 demand response auction mechanism guidelines for the additional demand response auction in 2018 for 2019 deliveries, except that contract terms shall be limited to one year of delivery for 2019; the Utilities shall offer contracts to all complying bids up to the simple average August capacity bidding price or the budget cap, whichever comes first; the Utilities shall work with Energy Division staff to ensure they use capacity values in bid selection criteria that appropriately prioritize bids for local resource adequacy; and the Utilities shall launch the additional 2018 auction no later than February 1, 2018 and shall submit their advice letters for approval of the auction results no later than May 1, 2018.

11. A Supply Side Working Group is established to discuss and develop proposals to the barriers and activities listed in Table 1 of this Decision. The Supply Side Working Group is responsible for accomplishing the tasks and providing status reports. On a quarterly basis, beginning on January 15, 2018, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall serve a status report to the service list in this proceeding describing the activities of the group and the tasks accomplished. A final report describing all activities and accomplishments shall be served no later than June 30, 2019. The Commission's Energy Division will oversee the activities of the Supply Side Working Group and the Utilities

shall organize and facilitate the working group meetings in consultation with the Energy Division

12. A Load Shift Working Group is established to discuss and develop proposals to the barriers and activities listed in Table 2 of this Decision. The work in the Load Shift Working Group should parallel work done in the California Independent System Operator's stakeholder process. The Load Shift Working Group is responsible for accomplishing the tasks and providing status reports and a final report. On a quarterly basis, beginning on January 15, 2018, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities), on behalf of the Load Shift Working Group shall serve a status report to the service list in this proceeding describing the activities of the working group and the tasks accomplished. No later than January 31, 2019, the Utilities, on behalf of the Load Shift Working Group, shall serve a final report to include final proposals, as described in Table 2. The final report may be used to inform a new rulemaking to develop a foundation for new models of demand response. The Commission's Energy Division will oversee the activities of the Load Shift Working Group.

13. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (the Utilities) shall hire a working group technical facilitator, in consultation with the Commission's Energy Division, to organize and facilitate the Load Shift Working Group. The Utilities may select a facilitator from a pool of available candidates drawn in consultation with Energy Division. The Utilities may create a memorandum account to track the cost of hiring the facilitator and may seek cost recovery of the facilitator in the advice letter filing for the 2020 Demand Response Portfolio update. The first

meeting of the Load Shift Working Group shall commence no later than January 31, 2018.

14. Pursuant to Public Utilities Code Section 1701.5, all issues addressed in the scoping memo of Rulemaking 13-09-011 have been resolved, except for the issue of new models, which this Decision determines shall be addressed in a future rulemaking. This proceeding remains open solely to address a pending application for rehearing.

This order is effective today.

Dated October 26, 2017, at Sacramento, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

Attachment 1

Steps to Implement Competitive Neutrality Cost Causation Principle

Step One:

A Community Choice Aggregator or Direct Access Electric Service Provider (Competing Provider) may file a Tier Three Advice Letter, served in accordance with General Order 96-B requesting that the Commission determine whether the Competing Provider's proposed demand response program is similar to an investor-owned (Competing Utility) program.

Step One A:

The Contents of the Advice Letter shall include: 1) a brief overview of the Competing Provider's proposed demand response program, ex ante load impacts for the proposed program in compliance with the adopted load impact protocols, and anticipated start date; 2) customer type description and approximate number of customers to be marketed to; 3) delineation of the proposed program as either a load modifying resource that is embedded in the California Energy Commission's unmanaged/base case load forecast or a supply resource able to be integrated into the California Independent System Operator's wholesale market and ability to demonstrate how the program meets either delineation; 4) description of how the Competing Provider will validate to the Commission that its customers will not receive an incentive for the use of prohibited resources during a demand response event; 5) description of whether the Competing Provider's demand response program will use a third party-aggregator; 6) the name of the competing utility; 7) the Competing Utility's program(s) that the provider considers to be similar and an explanation, pursuant to this Decision, and the Competing Utility's previous year's ex ante load impact for the program(s) as provided in the annual Load Impact Protocol filings.

Step Two:

The Tier Three Advice Letter will include a protest period, staff analysis, and proposed resolution. A workshop may be held to assist in the understanding of parties' positions. This process will follow the same process as outlined in the Commission's General Order 96B.

Step Three:

If the outcome of the resolution determines that the Competing Provider's proposed demand response program is similar, the Competing Utility has 30 days from the issuance of the resolution to begin the process to cease cost recovery by and targeted marketing to the Competing Provider's customers of the similar program. By the 60th day, a letter shall be sent to the affected customers notifying them of the change. The letter will also explain to customers of the Competing Provider currently enrolled in the Competing Utility's similar demand response program that they will cease to be eligible for that program at the end of the year but will be eligible to participate in the Competing Provider's similar demand response program. No later than 365 days following the issuance of the resolution, the Utility shall complete the changes.

Step Four:

Within one billing cycle following the end of cost recovery and targeted marketing by the Competing Utility to the Competing Providers' customers of the similar demand response program(s), affected customers shall receive a bill credit for cost recovery of the similar program(s).

(END OF ATTACHMENT 1)