Decision **PROPOSED DECISION OF ALJ HYMES** **(Mailed 10/28/2014)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

DECISION RESOLVING SEVERAL PHASE TWO ISSUES AND ADDRESSING THE MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT ON PHASE THREE ISSUES

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DECISION RESOLVING SEVERAL PHASE TWO ISSUES AND ADDRESSING THE MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT ON PHASE THREE ISSUES

Summary

This decision adopts interim policies and guidelines to enhance the role of demand response in meeting California's electric resource planning needs and operational requirements while initiating the steps toward a future solution. During the review of Phases Two and Three of this proceeding, a majority of the parties reached a compromise on how to resolve Phase Three issues.

The parties' settlement includes the establishment of three main demand response working groups and the performance of a study to determine the potential of demand response in each of the service areas of Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company. The Commission adopts most of the settlement agreement between these parties, but because the settlement provides a path toward resolution of Phase Three issues, rather than resolution itself, we modify the settlement to ensure resolution of all the issues in a timely manner. Accordingly, this decision approves the study as well as the establishment of the working groups, but sets specific work products and timelines for these working groups. The Commission finds that the settlement fails to address all issues in the proceeding and thus modifies the settlement to ensure these issues are resolved.

In addition, this decision also adopts policies for the Phase Two issues of cost allocation and the use of backup generators. We also address issues regarding the proposed demand response auction mechanism.

This proceeding remains open to address revisions to the cost-effectiveness protocols in Phase Two and other issues in Phase Three of this proceeding.

1. Background

The Commission initiated Rulemaking (R.) 13-09-011 to enhance the role of demand response in meeting California's resource planning needs and operational requirements.[1] The OIR stated that the rulemaking will review and analyze current demand response programs to determine whether and how to bifurcate the programs; create an appropriate compensative procurement mechanism for supply-side demand response resources; determine the program approval and funding cycle; provide guidance for transitional years; and develop and adopt a roadmap for coordination with other proceedings and state agencies. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE) (together, the Utilities) were named as respondents in the OIR.

Following an October 24, 2013 prehearing conference, the assigned Commissioner and Administrative Law Judge issued a November 14, 2013 Ruling and Scoping Memo that determined the proceeding would be conducted in four phases: Phase One, dealing with the issues of bridge funding; Phase Two, dealing with the issue of whether to bifurcate and other foundational issues such as cost allocation and recovery, the use of backup generators (BUGs), and revising the cost-effectiveness protocols; Phase Three, dealing with the issues of future program design and operations; and Phase Four, dealing with the issue of a future roadmap. The Scoping Memo also determined the schedule and scope of issues for Phases One and Two of the proceeding.

Phase One issues were resolved through two decisions: Decision (D.) 14-01-004 and D.14-05-025, which approved a two-year bridge fund budget

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[1] The Commission adopted the Order Instituting Rulemaking (OIR) on September 19, 2013.

and associated program revisions. D.14-05-025 also closed Phase One. Phase Two issues were initially addressed in D.14-03-026, which determined that the Commission should bifurcate demand response programs into load modifying resources and supply side resources, but did not determine the issue of how to categorize the various programs. Thus, several Phase Two issues remained unresolved.

On April 2, 2014, the assigned Commissioner and Administrative Law Judge issued a Ruling and Revised Scoping Memo that determined the outstanding schedule for the continuation of Phase Two and the scope and schedule for Phase Three. The issues yet to be determined in Phase Two are the revision of the cost-effectiveness protocols, cost allocation and cost recovery, and the use of BUGs. As indicated in the Revised Scoping Memo, the issues to be resolved in Phase Three include:

- Goals for Demand Response
    - Review past and current goals;
    - Determine how to measure and increase participation in demand response;
    - Determine how to set annual goals for demand response participation;
    - Set annual goals for demand response participation; and
    - Determine how to prevent the devaluation or soloing of the two categories of demand response programs.
- Resource Adequacy Concerns (as directed by D.14-03-026)
    - Determine parties' specific resource adequacy concerns as they specifically relate to the bifurcated framework of demand response programs; and
    - Determine the cause of these concerns and recommendations for resolving them.

- California Independent System Operator (CAISO) Market Integration Costs (as directed by D.14-03-026)
    - Capture and analyze the costs of CAISO market integration; and
    - Determine whether the estimated costs are considered high, and the extent to which they are a barrier to CAISO market integration.
- Supply Resources Issues
    - Determine the characteristics of each demand response program the Commission should use to categorize the current and future demand response programs;
    - Specify into which category each current demand response program should be located by analyzing the characteristics of each program;
    - Determine whether portions or groups of customers in exiting programs can be sub-aggregated and designated as Supply Resource;
    - Develop, pilot, and implement a competitive procurement mechanism for demand response (as directed by D.14-03-026.);
    - Determine how to measure and set annual goals for the amount of demand response that should be integrated into the CAISO market;
    - Set annual goals for the amount of demand response to be integrated into the CAISO market;
    - Determine mechanisms to modify current programs and design new programs that meet forecasted needs;
    - Determine the roles of the Utilities and Third Party Providers in administering the supply resources (as directed by D.12-04-045); and
    - Address Dual Participation Issues.
- Load Modifying Resources Issues

- Determine how to improve current load modifier programs to meet forecasted needs;
- Determine how to measure and set annual goals for load impacts and the rules for reaching those goals;
- Determine the role, if any, that the load impact protocol will serve in the realignment of the load modifying resources and supply resources;
- Determine the roles of Utilities and Third Party Providers in administering the load modifying resources (as directed by D.12-04-045); and
- Address Dual Participation Issues.

- Program Budget Application Process
    - Determine the length of budget cycles; and
    - Determine the need of and frequency of budget oversight reviews or audits.

Testimony and reply testimony on all issues but the revision of the cost effectiveness protocols was served in May 2014. Evidentiary hearings scheduled for the week of June 9, 2014 were replaced with a brief hearing and two and a half days of workshops facilitated by the Administrative Law Judge.[2] On June 23, 2014, the Administrative Law Judge issued a Ruling proposing changes to the cost-effectiveness protocols and asking for responses to specific questions on those changes as well as general responses to the proposed changes.

As a result of the June workshops, the parties held subsequent settlement discussions over the course of six weeks. During a prehearing conference on July 30, 2014, representatives of the parties engaged in settlement discussions

[2] On August 18, 2014, a report identified as the June Workshop Report was entered into the record of this proceeding. This report was written by the Utilities with comments and replies filed by the parties.

stated that a settlement had been reached and that a settlement agreement was in the process of being finalized. Additionally, the representatives stated that no settlement had been reached on Phase Two issues and requested that briefing be permitted on these issues and one additional Phase Three issue. The representatives explained that a specific issue related to the Phase Three issue of a procurement mechanism could not be settled and requested that briefing on this issue also be permitted. During the prehearing conference, the parties discussed the upcoming deadline for filing comments on revisions to the cost-effectiveness protocols and requested an extension. The Administrative Law Judge suspended the comment deadlines for the June 23, 2014 Ruling regarding revisions to the cost-effectiveness protocols until further notice.[3]

On July 31, 2014, the Administrative Law Judge issued a Ruling revising the briefing schedule addressing specific Phase Two issues, and abbreviating the time to comment on the proposed settlement, once filed. The Administrative Law Judge required that objections to the shortened time period be filed by August 4, 2014; no party filed an objection to the abbreviated comment time. On August 4, 2014, a majority of the parties in this proceeding (the Settling Parties)[4] filed a joint motion requesting adoption of a Settlement Agreement (Settlement) on Phase Three issues (Joint Motion). The Joint Motion and Settlement (Attached

[3] The Administrative Law Judge issued a Ruling on August 31, 2014 confirming the suspension of the comments to the June 23, 2014 Ruling.

[4] The Settling Parties are: (in alphabetical order) Alliance for Retail Energy Markets, CAISO, California Large Energy Consumers Association (CLECA), Clean Coalition, Comverge, Inc., Consumer Federation of California, Direct Access Customer Coalition, EnergyHub/Alarm.com, EnerNOC, Inc., Environmental Defense Fund, Johnson Controls, Inc., Marin Clean Energy, Office of Ratepayer Advocates (ORA), Olivine, Inc., PG&E, SDG&E, Sierra Club, SCE, and The Utility Reform Network (TURN).

as Appendix 1) are described below. In response to the Joint Motion, Calpine Corporation (Calpine) filed comments on August 25, 2014 opposing portions of the settlement. Calpine neither presented any material contested issues of fact nor did it request a hearing on the Settlement. Thus, pursuant to Rule 12.3, no hearing on the Settlement was held. On September 8, 2014, a subset of the Settling Parties[5] filed a reply to the Calpine comments.

On August 25, 2014, the following parties filed opening briefs on the remaining Phase Two issues and the unsettled Phase Three issue: CLECA, the Direct Access Customer Coalition and the Alliance for Retail Energy Markets (DACC/AReM), Joint Demand Response Parties,[6] Marin Clean Energy, ORA, PG&E, SDG&E, SDG&E/TURN, Shell Energy, Sierra Club/Natural Resources Defense Council, SCE, and TURN. Reply briefs on these issues were filed on September 8, 2014 by Consumer Federation of California, DACC/AReM, Marin Clean Energy, ORA, and SDG&E, as well as three joint replies: 1) a joint reply by CLECA, PG&E, SDG&E, SCE and TURN, (Joint Reply A); 2) a joint reply by Sierra Club and Natural Resources Defense Council (NRDC) (Joint Reply B); and 3) a joint reply by CLECA, Joint Demand Response Parties, PG&E, and SCE (Joint Reply C).

Because this interim decision does not settle all matters in Phases Two or Three of the proceeding, the record has not been submitted and both Phases remain open.

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[5] The subset of the Settling Parties are: the CAISO, CLECA, Clean Coalition, Comverge, Inc., EnerNOC, Inc., Environmental Defense Fund, Johnson Controls, Inc., Olivine, Inc., PG&E, SDG&E, Sierra Club, and SCE.

[6] The Joint Demand Response Parties are Comverge, Inc., EnerNOC, Inc., and Johnson Controls, Inc.

2. Overview of Joint Motion and Settlement

The Settlement addresses five overlapping Phase Three issue areas: 1) Demand Response Goals, 2) Demand Response Valuation and Program Categorization, 3) Demand Response Auction Mechanism/Utility Roles/Future Procurement, 4) CAISO Integration, and 5) Budget Cycles. Each is briefly described below. As stated previously, the Settlement does not address the remaining Phase Two issues of revision of the cost-effectiveness protocols, review of cost allocation or the use of BUGs. The issues of cost allocation and backup generation are discussed in a subsequent section of this decision. The revision of the cost-effectiveness protocols will be addressed in a later decision.

As stated in its Joint Motion, the Settlement, on the whole, represents the Settling Parties' concurrence on the manner in which the Commission should currently resolve the five issue areas. The Settling parties contend that the Settlement allows for a reasonable transition to a competitive market for demand response supply resources that improves and increases the level of all demand response resources available to meet both current and future energy needs.[7] The Settlement seeks to establish a process with resolution in the not-too-distant future and therefore, the Settling Parties recommend that the Commission allow for an additional three-year application process following the 2015-2016 bridge funding. The Settling Parties agree that the Utilities will submit funding and program redesign (or new program) proposals for both supply resources and load-modifying resources in their November 2015 applications.[8]

[7] Motion for Adoption of Settlement Agreement at 13.

[8] D.14-01-004 at 8 stated that "unless otherwise revised in a future decision, the deadline for the utilities to file applications for post-2016 demand response programs is rescheduled to November 30, 2015."

2.1. Issue Area 1: Demand Response Goals

The Settling Parties agree to an interim statewide event-based demand response program goal of five percent of peak load and a process and criteria for establishing future firm demand response goals specific to each of the Utilities. The Settlement specifies the criteria for this firm goal and lays out a timetable and process, including the development and completion of a Demand Response Potential Study (Study), which will inform the firm goal.

2.2. Combined Issue Area 2 and Issue Area 4: Valuation / Program Categorization and CAISO Integration

The Settling Parties conclude that the issues of program categorization and valuation in Issue Area 2 are interrelated with the issues regarding CAISO integration (Issue Area 4). Thus, these two areas are discussed together.

While the Settling Parties recognize that the Commission requires demand response program bifurcation to begin in 2017, they contend that the characteristics determining the categorization of each demand response program can be better addressed by working groups composed of the Settling Parties as well as other stakeholders. Therefore, in the Settlement, the Settling Parties recommend that the Commission continue the current system and local resource adequacy valuation of demand response programs through 2019 to provide sufficient time to gain a better understanding of costs and existing barriers to CAISO integration. Furthermore, the Settling Parties recommend the development of three technical non-policy working groups to inform the categorization and valuation of demand response programs after 2019: Supply Resource Demand Response Integration Working Group, Load Modifying Resource Demand Response Valuation Working Group, and Load Modifying Resource Demand Response Operations Working Group.

The purpose of the Supply Resource Demand Response Integration Working Group (Supply Working Group) is to: a) identify areas where requirements for integrating supply resources into the CAISO energy markets are adding significant cost and complexity; and b) recommend program modifications and operational techniques so that demand response programs will be more suitable and successful as supply resources.

The purpose of the Load Modifying Resource Demand Response Valuation Working Group (Valuation Working Group) is to develop recommendations on: a) how event-based and nonevent-based load modifying resources should be valued after 2019; b) how load modifying resources should be incorporated into the California Energy Commission forecasts; and c) how load modifying resources will be valued for setting and informing resource adequacy proceedings, the long term planning proceeding, demand response cost-effectiveness determinations, and future distribution planning needs. These recommendations will be shared with the appropriate agency.

The purpose of the Load Modifying Resource Demand Response Operations Working Group (Operations Working Group) is to identify and develop processes that allow the CAISO to better incorporate load modifying resources into its operations so that the value of load modifying resources is fully captured.

The Settlement includes charters for all three working groups that outline the purpose, products, structure, governance, schedule and prioritization of each group.

2.3. Issue Area 3: Demand Response Auction Mechanism, Utility Roles, and Future Procurement

During discussions regarding Issue Area 3, the Settling Parties concluded that the costs and complexities in the CAISO market need to be reduced and, thus, recommend that the Commission proceed with a two-year pilot of the proposed Demand Response Auction Mechanism (DRAM). During the two-year pilot, the Commission could not only gain CAISO market experience through the pilot, but also hopefully reduce costs and complexities through the Supply Working Group previously discussed. Furthermore, the Settling Parties also recommend that the DRAM design, protocol, and standard offer contracts be developed by a broad public stakeholder process convened in December of 2014. The result of the stakeholder process would be submitted to the Commission for approval. Additionally, the winning contracts in the DRAM would also be submitted to the Commission for approval. To cover the costs of the DRAM pilot, the Settling Parties request that funding from the 2015-2016 bridge funding be authorized and that the fund shifting rules be lifted for the purposes of funding the DRAM pilot.

2.4. Issue Area 5: Budget Cycle

The Settling Parties agreed during settlement discussions that the development of future budget cycles require careful consideration and should be coordinated with other demand response and procurement changes taking place. Thus, the Settling Parties recommend one additional three-year budget cycle (2017-2019), with mid-cycle reviews, prior to the implementation of longer budget cycles. The longer budget cycles would be considered through a stakeholder process beginning no later than April 1, 2015 with a final proposal submitted by the stakeholders in December 2015.

3. Standard of Review of Settlements

The requirements for Settlements are set forth in Article 12, Rules 12.1 through 12.7 of the Commission's Rules of Practice and Procedure. Rule 12.1(a) requires parties to submit a settlement by written motion within 30 days after the last day of hearing. Because hearings were suspended, the time limit does not apply here. Consistent with Rule 12.1(b), the Settling Parties convened a Settlement Conference on July 23, 2014, with notice and opportunity to participate provided to all parties on June 27, 2014. Thus, the Settlement meets all requirements set forth in Rules 12.1(a) and (b).

The Commission must decide whether to approve the Settlement Agreement. The relevant standard is provided in Rule 12.1(d), which states that the Commission will not approve a settlement agreement unless the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest. In general, the Commission does not consider if a settlement reaches the optimal outcome on every issue. Rather, the Commission determines if the settlement as a whole is reasonable. A settlement agreement should also provide sufficient information to enable the Commission to implement and enforce the terms of the settlement. In the following sections, we discuss the terms of the Settlement and determine whether it meets the standards of Rule 12.1(d).

4. Discussion and Analysis of the Proposed Settlement

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

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

4.1. The Proposed Settlement, with Modifications, is Reasonable in Light of the Record

We find the Settlement, with modifications, to be reasonable in light of the record before us. The modifications address several shortfalls of the settlement. One specific concern is the Settlement's requirement that we retain current system and local resource adequacy valuation for demand response based on existing methodology through 2019, an issue that the Commission has consistently stated as being outside the scope of this proceeding. Additionally, we generally find that the Settlement as proposed does not provide sufficient oversight of the process by the Commission, nor can we delegate our oversight authority to Commission staff, as suggested by the Settlement. Furthermore, the Settlement proposes tasks and products that do not address all aspects of the scope of Phase Three of this proceeding. Lastly, we are concerned about the length of the proposed timeline. While we reiterate our previous finding that the integration of demand response into the CAISO market is a complex and technical matter, we remain vigilant in moving forward in a reasonable pace but without unnecessary delay. As such, the modified Settlement, if the parties elect to accept such modifications, provides more specifics on items such as tasks, products, timeline and reporting requirements. We discuss the Settlement, its shortfalls, and our modifications below. We also consider the concerns presented by Calpine.

The Settling Parties contend that the resolution of any one term or issue area cannot be assessed separately or discretely but rather as a package. Despite the Settling Parties contention that the Settlement cannot be evaluated piece by piece, it is the Commission's responsibility that all issues in the scoping memo be addressed.[9] Furthermore, it is not the Settling Parties' right or privilege to pick and choose whether a scoping memo issue should be resolved. Because the proposed Settlement fails to provide resolution of several important Phase Three issues, we discuss the Settlement and our modifications for each issue area as presented in the proposed settlement and in comparison with the issues set forth in the Revised Scoping Memo.

4.1.1. Issue Area 1 is Reasonable with Modifications

Issue Area 1 addresses the subject of demand response goals and the performance of a demand response potential study (Study). As set forth in the April 2014 Scoping Memo, this rulemaking shall review past and current goals to determine how to measure and increase participation in demand response and how to develop annual goals for such participation. The rulemaking shall also

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[9] Public Utilities Code Section 1701.5 requires the Commission to resolve the issues raised in the scoping memo by the eighteen month deadline.

establish annual goals while preventing the devaluation of load modifying or supply resources. Table 1 below lists each issue from the April 2014 Revised Scoping Memo that should be addressed in Issue Area 1 and the means by which the issue is addressed. Shaded areas are those issues that have been resolved. Non-shaded areas are those issues that will be resolved either through the work of the Settlement as proposed or through a modification of the Settlement.

TABLE 1

SCOPING MEMO ISSUES ADDRESSED IN ISSUE AREA 1

SCOPING MEMO ISSUE	MEANS BY WHICH ADDRESSED
Review past and current goals.	Workshop: See June Workshop Report at II.F. Settlement: Through Settlement Discussions, See Settlement at 6-7, 12.
Determine how to measure and increase participation in demand response and determine how to set annual goals for demand response participation.	Settlement: Demand Response Potential Study, See Settlement at 13-17.
Set annual goals for demand response participation.	Settlement: Demand Response Potential Study, See Settlement at 13-17.
Determine how to prevent the devaluation or soloing of the two categories of demand response programs.	Settlement: Demand Response Potential Study and Valuation Working Group, See Settlement at 16.2.b. and 19 at 1.b.

The Settling Parties state that the Commission previously established an aspirational goal, of five percent of peak load, for statewide price-responsive demand response.[10] The Settling Parties further state that, as of April 2014, the Utilities together have only reached 3.9 percent of the system peak loads for all three utilities.[11] The Settlement provides a set of criteria for establishing future

[10] Settlement at 6.

[11] Settlement at 6-7.

goals, which will be informed by the results of the proposed Study. Until the future goals are developed, the Settling Parties agree and request that the Commission maintain an interim statewide aspirational goal for cost-effective, event-based demand response equal to five percent of the sum of the individual peak demands of the three utilities.[12]. No party opposed this portion of the proposed Settlement.

In the OIR establishing this rulemaking, we stated that a goal of this proceeding was to increase the penetration of demand response programs by examining how we frame the programs, how they are offered and procured.[13] We have not performed this examination and the testimony in this proceeding only provides opinions on what demand response goals should be without substantial facts to support those opinions. During the June workshops, parties discussed the concept of a study to look at the potential of demand response in California. Over the course of those discussions, parties stated that a study should look at the potential for demand response based on value and on need.[14] Serendipitously, Commission staff revealed that they are currently working on a contract for a consultant to study demand response potential and needs.[15]

The Settlement does not set a specific future goal, but the process it sets forth will lead us to that determination. Studying the potential of demand response in the utilities' service areas will assist the Commission in setting a goal

[12] The Settling Parties further clarified this during the prehearing conference on July 30, 2014. TR Vol. 3 at 80, lines 5-25.

[13] OIR at 15.

[14] June Workshop Report at Section II.F.1(.a.).

[15] *Id.* at Section II.H.4.

based on potential, needs, and value. While we are concerned about the time such a study could take, we are encouraged that the Commission has previously authorized the funding for such a study, thus reducing the timeline. We also emphasize that, although the Commission is committed to transparency in our activities, we must be prudent in our time management of implementing the Study. We therefore modify this section of the settlement to address these and other concerns, as further discussed below.

Our first concern relates to the interim proposed goal. The Settling Parties state that current Commission policy does not include emergency or reliability demand response programs toward the attainment of the five percent goal that was established in the Energy Action Plan.[16] The Settling Parties fail to mention that the Commission previously approved this goal in D.03-06-032.[17] At that time, the Commission was focused primarily on developing programs that are triggered for economic purposes, rather than programs that are used for reliability purposes.[18] The proposed Settlement provides no justification as to why emergency or reliability demand response programs[19] should now be included in the interim goal. In comments to the proposed decision, the Settling Parties contend that it is reasonable to include reliability and emergency programs in the interim goal but, as in the Settlement, provides no reasoning for

[16] Settlement at 6.

[17] D.03-06-032 at 7-10 and Ordering Paragraph No. 1.

[18] D.03-06-032 at 8, footnote 14.

[19] Examples of emergency or reliability programs are the Base Interruptible Program (BIP) and the Agricultural Pumping Interruptible (AP-I) program.

changing current Commission policy. [20] Thus, we modify the Settlement to confirm the policy as set in 2003: emergency or reliability programs do not count toward the proposed interim five percent goal. Although the Commission omits emergency or reliability programs for attaining the interim goal, these programs continue to have value and should not be discontinued.

We are also concerned that the Settlement does not adequately address the issue of the categorization of programs. Thus, the Commission will address this issue following the completion of the Study, as it should inform the Commission on the issue of categorization. The Commission will review the results of the Study and determine a final outcome in a future decision. In comments, the Settling Parties contend that categorization is unnecessary since programs can be partially bid into the CAISO market.[21] Settling Parties argue that current programs such as the Capacity Bidding Program are partially bid into the CAISO market. However, the Commission finds that until the results of the Study and the Working Groups are reviewed by the Commission, we do not have adequate information to make this determination.

Lastly, we are concerned about balancing the transparency of the Study with the proposed schedule for completing the study. To reflect such a balance, the Commission directs the Study to be designed by staff using the parameters of the Settlement as a guideline. Stakeholders will be provided an opportunity to comment on a draft research plan for the Study; the comments will be fully considered by staff.

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[20] Settling Parties Comments to Proposed Decision at 6.

[21] *Id.* at 7.

Staff is directed to begin the contracting process for the Study immediately and to present the draft research plan to stakeholders during a workshop facilitated by the assigned Administrative Law Judge. Parties' comments shall be due 30 days following the workshop. The Study itself shall be completed within one calendar year from its commencement. No later than 60 days following the completion of the Study, a final report from the consultant, including future demand response goals, shall be provided to the Administrative Law Judge for comment by the parties, and then review and final approval by the Commission.

D.12-04-045 anticipated that the potential of demand response and a market assessment were important to the success of demand response programs. As such D.12-04-045 approved $3 million for research on these issues. We direct Commission Staff to utilize the previously authorized $3 million for the Study discussed above. Furthermore, because the Study will not be completed until after the expiration of the original authorization for the funds, we approve an extension for these funds through December 31, 2016.[22]

4.1.2. Issue Areas 2 and 4 are Reasonable with Modifications

The Settling Parties assert that the topics of Issue Area 2, which involve demand response valuation and program categorization, are integral to Issue Area 4, encompassing the CAISO market integration costs and, therefore, should be addressed together. The two issue areas comprise the April 2014 Scoping Memo categories of resource adequacy concerns, supply and load modifying resource issues, and CAISO market integration costs.

[22] The funds authorized in D.12-04-045 expire at the end of the State fiscal year, June 30, 2015. This extension will move the funds into the 2015-2016 bridge funding budget cycle.

As set forth in the April 2014 Scoping Memo, R.13-09-011 shall determine the parties' resource adequacy concerns, the causes for those concerns, and resolutions. The Rulemaking shall also capture and analyze the costs of CAISO market integration, and determine whether the costs create barriers to integration. In regard to the load modifying and supply resource issues, the Rulemaking is tasked to determine the characteristics of each demand response program in order to categorize them as either a load modifying or supply resource and set goals for each category. Furthermore, to ensure a smooth transition to bifurcation, the Rulemaking is tasked to determine modifications to current programs and proposed design for new programs. Finally, pursuant to D.12-04-045, this Rulemaking shall define the roles of utilities and third party providers in administering both supply and load modifying resources. Table 2 below lists each issue from the April 2014 Revised Scoping Memo that should be addressed in Issue Areas 2 and 4, and the means by which the issue is addressed. Shaded areas are issues that have been resolved. Non-shaded areas are issues that will be resolved either through the work of the Settlement as proposed or through a modification of the Settlement.

TABLE 2

SCOPING MEMO ISSUES ADDRESSED IN ISSUE AREAS 2 & 4

SCOPING MEMO ISSUE	MEANS BY WHICH ADDRESSED
Determine parties' specific resource adequacy concerns and determine the cause of these concerns.	Workshops: June 9, 2014, See June Workshop Report at Section II.D.
Determine recommendations for resolving the resource adequacy concerns.	Settlement: Valuation Working Group, See Settlement at Attachment B.
Capture and analyze the costs of CAISO market integration.	Workshops: June 9 – 10, 2014, See June Workshop Report at Section II.C.
Determine whether the estimated costs for integration are high, and whether they are a barrier to CAISO market integration.	Settlement: Integration Working Group, See Settlement at 19 and Attachment A.

TABLE 2 SCOPING MEMO ISSUES ADDRESSED IN ISSUE AREAS 2 & 4	
Determine the characteristics of each demand response program the Commission should use to categorize the current and future demand response programs.	Modification: Include as part of the Demand Response Potential Study and the resulting recommendations.
Specify into which category each current demand response program should be located by analyzing the characteristics of each program.	Modification: Include as part of the Demand Response Potential Study and the resulting recommendations.
Determine whether portions or groups of customers in exiting programs can be sub-aggregated and designated as Supply or Load Modifying Resource.	Modification: Include as part of the Demand Response Potential Study and the resulting recommendations.
Determine how to measure and set annual goals for the amount of demand response that should be integrated into the CAISO market.	Modification: Include this work in the Study and the resulting recommendations.
Set annual goals for the amount of demand response to be integrated into the CAISO market.	Modification: Include this work in the Study and the resulting recommendations.
Determine mechanisms to modify current programs and design new programs that meet forecasted needs.	Settlement: Integration Working Group, See Settlement at Attachment A.
Determine the roles of Utilities and Third-Party providers in administering the supply resources and the load modifying resources.	Modification: Not addressed by the Settlement. A future Ruling will be issued and this subject will be addressed in a future decision.
Address Dual Participation Issues.	Future Decision: This issue is related to the cost-effectiveness protocols and will be addressed in a future decision.
Determine how to improve current load modifying programs to meet forecasted needs.	Settlement: Valuation Working Group, See Settlement at Attachment B.

TABLE 2 SCOPING MEMO ISSUES ADDRESSED IN ISSUE AREAS 2 & 4	
Determine how to measure and set annual goals for load impacts and the rules for reaching those goals.	Settlement: Valuation Working Group, See Settlement at Attachment B.
Determine the role, if any, that the load impact protocol will serve in the realignment of the load modifying resources and supply resources.	Settlement: Valuation Working Group, See Settlement at Attachment B.

In the Settlement, the Settling Parties acknowledge that demand response program bifurcation will begin in 2017 and that the Utilities will be required to provide redesigned and new programs in their 2017-2019 Demand Response Program and Budget Application. However, the Settling Parties contend that further analysis is required with regards to the valuation used to calculate the system and local resource adequacy credits for the current programs. Furthermore, the Settling parties also contend that a better understanding of costs and existing barriers to CAISO market integration, and potential resolution would be facilitated by continued dialogue. Thus, as previously described, the Settlement proposes the formation of three working groups that, in addition to the results of the demand response potential study, will resolve the matters in Issue Areas 2 and 4.

Calpine objected to this portion of the Settlement, concluding that the proposal would grandfather the resource adequacy counting of demand response programs until 2020 without any consideration of their actual contributions to reliability. Calpine contends that retaining the current resource adequacy counting could put reliability at risk and increase ratepayer costs.

Calpine also claims that the Settlement disregards the Commission's goal of increasing the amount of demand response bid into the CAISO market.[23]

In D.14-03-026, the Commission determined that bifurcation of demand response programs would begin in 2017. Furthermore, while we noted that bidding demand response into the CAISO market is a complex process based on multiple factors, we also confirmed that it has been an objective of the Commission since 2007.[24] Calpine's concern regarding maintaining the current counting methodology is valid. As pointed out in the response to Calpine's concerns, demand response treatment for resource adequacy purposes is established through the annual resource adequacy proceedings.[25] In fact, in D.14-03-026, we confirmed that setting resource adequacy capacity for demand response has been and will continue to be resolved in the resource adequacy proceeding. The revised Scoping Memo requires that we identify the concerns regarding resource adequacy, determine the cause of the concerns and provide recommendations to resolve them. The Settlement provides a process for this within the confines of the Valuation Working Group.

We agree with Calpine that there is little justification for delaying the use of a more accurate treatment of demand response resources for resource adequacy purposes until 2020.[26] According to the charter for the Valuation Working Group, "recommendations should be completed by May 1, 2015 so that they can be factored into the timeline established by the Joint Agency Steering

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[23] Calpine Comments on Settlement Agreement at 2.

[24] *Id.* at Finding of Fact Nos. 17 and 18.

[25] Response to Calpine Comments at 6.

[26] Calpine Comments at 5.

Committee and for the 2017 [Resource Adequacy] rules."[27] We recognize that the Settlement includes maintaining, until 2020, the current valuation used to calculate the system and local resource adequacy credits for all existing programs. Nevertheless, as noted by Calpine, "delaying a more accurate accounting of demand response's contributions toward meeting resource adequacy requirements nullifies an important purpose of bifurcation and is consistent with the Commission's established policy that demand response be held to the same requirements as other generation resources."[28] In response, the Settling Parties state that the Settlement in no way advocates a less accurate treatment of demand response resources prior to 2020. Rather, the Settling Parties "have generally agreed to a measured approach to implementing bifurcated demand response and direct participation in the CAISO market."[29]

We recognize the importance of regulatory certainty for demand response customers and providers,[30] but we disagree that 2020 is a reasonable timeline for full implementation. Instead, we require full implementation of bifurcated demand response by 2019, the third year of the transition budget cycle of 2017-2019. Furthermore, we affirm that resource adequacy policy developed in R.14-10-010 and its successor proceeding should flow through to demand response resources as it is developed.

In comments to the proposed decision, the Settling Parties urged the Commission to confirm that full implementation of bifurcation includes

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[27] Settlement at Attachment B at 3, section 12.

[28] Calpine Comments at 5.

[30] *Id*. at 7.

[30] *Id*. at 7.

1) adoption and implementation of an appropriate methodology to value and operationally account for load modifying demand response, 2) adoption of rules for resource adequacy treatment of all forms of demand response, 3) adoption and implementation of key requirements to integrate demand response into the CAISO markets where appropriate.[31] We confirm that the Commission considers full bifurcation of demand response to include these three items, as well as the adoption of the categorization of demand response programs. We reiterate and emphasize, however, that adoption of resource adequacy treatment will take place in the resource adequacy proceeding. Furthermore, once that adoption occurs, the rules will automatically and immediately flow through to this proceeding.

Furthermore, we find that many issues in the April 2014 Scoping Memo are not resolved, but we expect that the resolution of most of these issues will occur through the process proposed in the Settlement. The issues regarding CAISO market integration costs will be addressed through the Integration Working Group. Most Supply Resources issues (the demand response auction mechanism is discussed in Issue Area 3) will be addressed through a combination of the results of the Study and the efforts of the Integration Working Group. Load Modifying Resource issues will be addressed through a combination of the results of the Study, and the efforts of both the Valuation Working Group and the Operations Working Group. The Settlement does not distinctly address the actual categorization of current programs or goals for the amount of demand response to be integrated into the CAISO market. Thus, as we pointed out in our discussion of Issue Area 1, we add this task to the design of the Study.

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[31] Settling Parties Comments on Proposed Decision, November 17, 2014 at 9-10.

We adopt the provisions of Issue Areas 2 and 4 of the Settlement, with the following modifications:

- First, and foremost, the 2017-2019 demand response program cycle will be a full transitional cycle beginning with small steps toward bifurcation in 2017 and ending with fully implemented bifurcation in 2019. Resource adequacy credits will flow through to demand response programs once adopted by the Commission in the Resource adequacy proceeding. We acknowledge the desire by the Settling Parties to take a "measured approach" to the transition to bifurcation, but believe that the transition program cycle should end with a complete transition.
- As evidenced by the testimony in this proceeding, we find that the parties in this proceeding have expertise in the demand response issues being addressed in this rulemaking. However, the hiring of additional experts for the Valuation Working Group may be necessary and is approved with a cap of $200,000 for the duration of the Working Group.
- While we are not discounting a future contention that a demand response program can be partitioned into a load modifying and supply resource, the settlement includes little evidence to justify this statement. The Commission acknowledges that current programs are partially bid into the CAISO, i.e. Capacity Bidding Program based upon current CAISO requirements. However, until the Study and the Working Groups have completed their tasks, we cannot accept such claims. Any future contention must be accompanied by current and supporting facts.
- The process described in Section B.11.e of the Settlement, regarding the identification and resolution of how unmet goals can be met, shall be considered by the Commission in a separate decision following the publishing of the results of the Demand Response Potential Study. The results of the Study should assist the Commission in determining how unmet demand response goals can be met.
- The Valuation Working Group's charter notes that one of its objectives is to identify other values that load modifying resources may provide and recommend how that value should be

realized by resource owners. We encourage the efforts of the Valuation Working Group. To be effective its output will need to demonstrate that neither load modifying nor supply resources receive an unfair advantage through favorable valuation.

- During a prehearing conference on the settlement, the Settling Parties were asked how the working groups would report back to the Commission. In response, the Settling Parties stated that they envisioned Commission staff reporting back to the Commission because the working groups may not want to spend time engaged in writing exercises.[32] Given the limited resources of the Commission, and the possibility that Commission staff may not be available for every meeting of the working groups, we establish the following reporting requirements: a) Integration Working Group – Quarterly Reports (filed as compliance reports) on the meetings held, the products developed, and the groups' successes and missteps; the mid-year report referred to in the charter, which is to include proposed changes, priorities and time-line, shall also be filed no later than June 30, 2015, as a compliance report; b) Valuation Working Group – Given the narrow focus of this working group, we find that it is only necessary to file the May 1, 2015 report referenced in the charter, which shall be filed as a compliance report; c) Operations Working Group – Quarterly Reports (filed as compliance reports) on the meetings held, the products developed, and the groups' successes and missteps. The Quarterly Reports will be due on April 1, July 1, October 1 and January 1 until the completion of this proceeding. The Quarterly Reports may be filed by one or more representatives of the Settling Parties, but the ultimate responsibility of ensuring the filing of these reports shall fall on PG&E, SDG&E, and SCE.

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[32] TR, Vol. 3 at 186-187.

4.1.3. Issue Areas 3 is Reasonable with Modifications

Issue Area 3 addresses the DRAM, utility roles and future procurement. As set forth in the April 2014 Scoping Memo, pursuant to D.14-03-026, R.13-09-011 shall develop, pilot and implement a competitive procurement mechanism for demand response. The Rulemaking is also tasked with determining the roles of the utilities and third party providers in administering the supply resources. While this issue was listed as a Supply Resource issue in the Scoping Memo, the Settling Parties have included it as a DRAM-related issue. Table 3 below lists each issue from the April 2014 Revised Scoping Memo that should be addressed in Issue Area 3, and the means by which the issue is addressed. Shaded areas are issues that have been resolved. Non-shaded areas are issues that will be resolved either through the work of the Settlement as proposed or through a modification of the Settlement.

TABLE 3

SCOPING MEMO ISSUES ADDRESSED IN ISSUE AREA 3

SCOPING MEMO ISSUE	MEANS BY WHICH ADDRESSED
Develop, pilot and implement a competitive procurement mechanism for demand response.	Workshop: June Workshop Report at Section II.G.4. Settlement: See Settlement at 9-11 and 24-30.
Determine the roles of Utilities and Third Party Providers in administering the load modifying and supply resources.	Settlement: See Settlement at 9-11 and 24-30. Only addresses roles regarding administration of the DRAM pilot. Modification: Issue Ruling asking responses to questions regarding roles in administering demand response resources.

The Settling Parties contend that "many issues must be resolved in order for the DRAM to be implemented, including bidding rules, cost caps, and payment structure."[33] The Settlement proposes that while these issues are being resolved through a public working group, the Commission should embark upon a pilot of the DRAM with an auction in 2015 for 2016 delivery and a second auction in 2016 for 2017 deliveries.

Calpine objects to the Settlement "significantly reducing the role of DRAM from the primary means of securing supply resources, as contemplated by the original staff proposal, to a modestly sized pilot."[34] Calpine contends that despite the best efforts of the Commission to expedite the participation of demand response in the CAISO market, the Settlement only provides that the utilities will increase cost-effective supply resources as barriers to market integration are overcome.[35] In response, the Settling Parties disagree with Calpine's statements regarding a reduction in the role of the DRAM. The Settling Parties contend that the Settlement provides a process for the DRAM to be developed successfully on a pilot basis to improve the likelihood of success.[36]

Piloting the DRAM was first recommended by Commission staff during the June workshops. Commission staff suggested such a pilot for the first year in transitioning to third party direct participation.[37] Furthermore, ORA expressed concern regarding sufficient participation for a successful auction, if the auction

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[33] Settlement at 15.

[34] Calpine Comments at 7.

[35] *Ibid.*

[36] Response at 5-6.

[37] June Workshop Report at Section II.G.4.

is more than a pilot. In the OIR establishing this rulemaking, we identified several aspects of a competitive procurement mechanism that needed to be addressed, including looking at the strengths and weaknesses of the Commission's procurement mechanisms and lessons learned from other programs that could inform the design of supply-side demand response procurement.[38]

In discussing the justification for a pilot auction mechanism versus full implementation of the CAISO market integration, the Settlement states that successful integration will require substantially reducing the costs and complexity of integration.[39] Furthermore, the Settling Parties conclude that changes in the requirements for direct participation by demand response providers in the CAISO market are necessary to reduce the complexity and costs of participation.[40] The Settling Parties contend that the integration issues are central to the development of a fully implemented DRAM.[41] A DRAM pilot would allow the details of the auction mechanism to be refined with experience[42] while simultaneously resolving issues related to the cost and complexity of market integration. The Commission has approved the use of a pilot many times over the life time of the demand response programs.[43] A pilot is a cost-effective

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[38] OIR at 18.

[39] Settlement at 9.

[40] Motion for Adoption of Settlement at 15.

[41] Settlement at 9.

[42] Settlement at 10.

[43] *See, for example,* the pilots approved in concept in D.12-04-045 at 176.

way of implementing an idea, learning from that idea, and making changes to improve its success.

The record in this proceeding highlights the complexity of CAISO market integration. While the Commission would prefer full implementation of a competitive procurement mechanism in 2015, we recognize that many questions surrounding CAISO market integration remain unanswered. This was evident during the discussions in the June workshops where parties spent an afternoon discussing costs and technical aspects of integration and concluded that "more understanding of requirements for CAISO market integration is needed before better cost estimates can be offered."[44] As the Commission stated in D.14-03-026, bidding demand response into the CAISO market is a complex process."[45] Thus, we agree that the prudent approach is a two-year DRAM pilot, where we can learn from experience while simultaneously increasing our understanding of the CAISO complexities through the working groups. We do not agree with Calpine's opinion that the pilot will reduce the role of DRAM as a means of securing supply resources. Rather, the pilot will ensure that we take the appropriate steps to making the DRAM a successful means to procure supply resources.

The Settling Parties included the role of the Utilities in this portion of the settlement. According to the OIR, this Rulemaking shall address the policy regarding the role of the Utilities in demand response. The OIR noted that "[h]istorically, the Commission employed a utility-centric model of demand response procurement that allows only a limited role for third party aggregators.

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44 June Workshop Report at II.C.2

45 D.14-03-026 at Finding of Fact No. 17.

With the implementation of Rule 24, it should be possible for third party demand response providers to play a much larger role in the procurement of supply-side demand response."[46] Issue Area 3 of the Settlement does not adequately address this issue.

Solely addressing the role of the utilities as it relates to DRAM does not capture the entirety of this issue. In D.12-04-045, the Commission discussed forward looking issues, including demand response market competition. We noted that the changing nature of the grid calls into question whether a utility centric model for these programs and services can meet current and future needs.[47] At that time, the CAISO suggested that the Utilities should play a supporting role rather than a central role. We noted that given the uncertainty of market rules, etc., the Commission would address this issue in a Rulemaking. We find that this aspect of the role of the Utilities issue remains unresolved. A future ruling will be issued asking parties to address specific questions on this matter for resolution in a future decision in this proceeding.

The issue of utility roles aside, we find the terms and conditions set forth by the Settlement in Issue Area 3 to be reasonable, with modification. Thus, we adopt the Issue Area 3 terms and conditions with the following clarifications and modifications: a) In addition to the pilot design, protocol and standard contracts, the pilot design working group shall also develop transparent, standard evaluation criteria. The Utilities may not use their own respective valuation processes as noted in the Settlement;[48] b) the DRAM pilot design, requirements,

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[46] OIR at 16.

[47] D.12-04-045 at 190.

[48] Settlement at 25.

protocols, standard pro forma contracts, evaluation criteria and non-binding cost estimates will be filed at the Commission as a Tier Three advice letter no later than April 1, 2015 and c) fund shifting will be allowed for the sole purpose of funding the DRAM pilot with the following caveats: 1) Utilities shall not eliminate any other program in order to fund the pilot without proper authorization from the Commission; and 2) Utilities shall continue to submit a Tier Two Advice Letter before shifting more that 50 percent of any one program's funds to the pilot.[49]

It is the Commission's intention that PG&E, SDG&E, and SCE, by entering into the Settlement and requesting to work on the DRAM through the pilot design working group will be doing so in furtherance of Commission policy to increase the amount of demand response bid into the CAISO market. By furthering this policy, the Utilities will also be addressing issues critical and common to ratepayers under Commission jurisdiction, pursuant to the Commission's constitutional authority and authority under Public Utilities Code Section 701 and under the direction and continuing supervision by, and ultimate control of, this Commission sufficient to confer immunity from antitrust liability under the State Doctrine and consistent with FTC v. Phone Putney, 133 S.Ct. 1003 (2013.)

In prior decisions authorizing the Utilities to participate in a collaborative way, the State Action Doctrine affords private entities protection from antitrust liability when they act pursuant to state policy and under the active supervision of an agency such as the Commission.[50] It is our intention that the authority we

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[49] D.12-04-045 at Ordering Paragraph 4.

[50] D.10-06-009 at 8-9.

grant the Utilities to work on the DRAM pilot design working group, is sufficient to confer antitrust immunity under the State Action Doctrine. In particular, it is our intention that the activities of the Utilities in the DRAM pilot design working group shall be pursuant to the express direction and continuing supervision of the Commission through review and approval by the Commission of a final DRAM pilot design.

4.1.4. Issue Areas 5 is Reasonable with Modifications

Issue Area 5 addresses the subject of future budget cycles, specifically extended cycles. As set forth in the April 2014 Scoping Memo, this rulemaking shall determine the length of budget cycles and the need and frequency of budget oversight reviews or audits within a cycle.

TABLE 4

SCOPING MEMO ISSUES ADDRESSED IN ISSUE AREA 5

SCOPING MEMO ISSUE	MEANS BY WHICH ADDRESSED
Determine the length of budget cycles	Settlement: 2015 Working Group, See Settlement at 30-31.
Determine the need of and frequency of budget oversight reviews or audits	Settlement: 2015 Working Group, See Settlement at 30-31.

While the Settling Parties agree that a cycle longer than three years may be appropriate, they state that the development of an extended budget cycle requires careful consideration and coordination with other changes to the demand response program as a whole.[51] The Settlement proposes that the Commission permit one additional three-year demand response program cycle for the years 2017-2019, while changes are transpiring. Settling Parties suggest

[51] Settlement at 11.

that the final three-year cycle should include one mid-cycle review with a public workshop to allow input on mid-cycle revisions to the demand response programs in order to ensure and enhance program participation and performance. Furthermore, the Settlement proposes that a future working group, to begin in April 2015, will provide a proposal for extended budget cycles, to the Commission by December 31, 2015 for its approval.[52] The proposal would consider all demand response-related proceedings and activities. No party opposed this portion of the proposed Settlement.

In the OIR establishing this rulemaking, the Commission stated that it would consider extending funding cycles while balancing the following needs: regulatory certainty, the flexibility to terminate underperforming programs or to bring new programs online based on innovations, ensuring that portfolios are cost-effective and based on the best-available data.[53] The Settling Parties lay out a course for reviewing and making determinations on future budget cycles through a collaborative effort that addresses these issues.[54] We find this course to be reasonable. We adopt the terms and conditions set forth by the Settlement in Issue Area 5 with the following modifications:

a. Because this proceeding will be open when the Utilities are preparing their applications, a Ruling in this proceeding will be issued in May 2015 providing guidance on the 2017-2019 program cycle;

b. Because we consider this final three-year cycle to be transitional, we require two end-of-year review workshops, facilitated by the

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[52] *Id*. at 11 and 30.

[53] OIR at 16.

[54] *See, for example*, Settlement at 11 regarding uncertainty, Settlement at 30 requiring cost-effectiveness, and Settlement at 31 requiring the frequency of reviews.

assigned Administrative Law Judge. The workshops, to be held early in 2018 and again in early 2019, should ensure that each successive year of the transitional cycle moves the Commission closer to full CAISO market integration and full bifurcation implementation; and

c. We eliminate the provision that the Commission approve the extended budget cycle by March 31, 2016.

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

The Settlement, as modified, is consistent with the law and prior Commission decisions. As discussed above, the Settling Parties have complied with the provisions of Rule 12 regarding Settlements. As further explained below, the Settlement, as modified, is consistent with the Commission's prior decisions regarding demand response, especially bifurcation.

The goal of this Rulemaking, as stated in the OIR, is to enhance the role of demand response in meeting the State's long-term energy goals while maintaining system and local reliability. The multiple tasks outlined in the Settlement goes to the heart of this goal and, therefore, are aligned with the intent of the Rulemaking.

D.14-03-026 ordered the bifurcation of current demand response programs with operational bifurcation to begin with the 2017 program year.[55] The Settlement asserts that the Utilities will submit applications for new or redesigned programs in November 2015 which should have the characteristics necessary to meet specific pre-determined needs as either a load modifying or

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[55] D.14-03-026 at Ordering Paragraph 1.

supply resource.[56] This statement is in compliance with the bifurcation requirement.

Calpine contends that the Settlement does not comply with D.14-03-026 because resource adequacy credits will remain unchanged until 2020. Calpine's contention rests within the Settlement statement that "the current methodology used to calculate the system and local resource adequacy credits for the existing demand response programs should be retained through 2019."[57]

The Commission has already determined that complete implementation of bifurcation cannot occur until resource adequacy issues have been resolved.[58] The Settlement continues the resolution of these issues through the efforts of the Integration Working Group. Because the Commission has previously affirmed that integration into the CAISO market is complex, we accept that the complete resolution process will take more time than previously anticipated and, therefore, later than 2017. Furthermore, in D.14-03-026, the Commission did not order that the full implementation of bifurcation requires that only supply resources receive resource adequacy credit. In fact, the Commission stated that the rules regarding the counting of resource adequacy credits should and will be addressed in the resource adequacy proceeding.[59] Thus, we conclude that the Settlement, as modified, is consistent with the law and past Commission decisions.

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[56] Settlement at 8.

[57] *Ibid.*

[58] D.14-03-026 at 12 and at Finding of Fact 14.

[59] D.14-03-026 at 10-11.

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

The Settlement, as modified, is in the public interest for multiple reasons. First, it puts the Commission on a solid path toward resolution of Phase Three issues and thus another step closer to direct participation of demand response into the CAISO market. Second, the Settling Parties represent diverse interests, including residential and large energy customers, third party demand response providers, community choice aggregation providers, direct access providers, environmental organizations, and utilities, and therefore balances the various interests at stake.[60] Third, the Settlement strives to balance the interest of these various stakeholders while enhancing the role of demand response in California. Fourth, as a result of moving another step forward in the implementation of bifurcation and CAISO market implementation, the Settlement should lend in providing: a) reductions in peak electricity consumption; b) ratepayer savings through the avoidance of new generation construction; and c) reduced greenhouse gas emissions, as envisioned in the OIR.[61]

5. Discussion and Analysis of Briefing on the Remaining Phase Two and Phase Three Issues

During Settlement discussions, parties agreed that the Phase Two issues of cost allocation and the use of backup generation were better addressed through briefs. As such, the assigned Judge issued a Ruling setting a schedule that permitted opening and reply briefs on these two issues. In addition, the Settlement discussions of the DRAM led to an impasse regarding whether the

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[60] *See* D.11-12-053 at 76, discussing settlements.

[61] OIR at 3.

DRAM should be the preferred method of procurement and whether the Commission should ensure adequate participation in the DRAM pilot. The previously referenced Ruling allowed parties to include arguments on these issues along with briefs for the Phase Two issues. We address the arguments and resolution of these issues below.

5.1. Phase Two: Cost Allocation

As further described below, to determine the allocation of cost of the utility-provided demand response programs we confirm that, pursuant to prior Commission statements, the cost causation principles shall be utilized while simultaneously ensuring: a) consistency across all three utilities and b) the reduction of barriers to competition for direct access and community choice aggregation providers.

5.1.1. Background: Cost Allocation

The demand response programs established over the past twenty plus years provide multiple benefits of varying degrees to Californians: the reduction of generation capacity needs, the reduction in resource adequacy requirements, the reduction of energy prices in the CAISO energy market, the alleviation of transmission congestion, the protection of system and local grid reliability, and consumer education. All parties to this proceeding agree that demand response programs benefit California. The major difference between party positions arises when determining the extent to which a customer is benefitted and therefore the extent to which a customer should pay for that benefit. Currently the costs of most demand response programs are allocated to distribution rates.

Three parties contend that the current cost allocation is not appropriate. DACC/AReM state that demand response program costs should be properly allocated to the generation revenue requirement and that the Commission should require consistent cost allocation across the utilities.[62] DACC/AReM argues that the current allocation to distribution rates artificially lowers utility generation rates and creates barriers to entry for third party demand response providers.[63] To alleviate these problems, DACC/AReM recommends a set of uniform principles to achieve fairness and consistency. These five principles are summarized as: 1) Supply resources are generation substitutes and should be recovered in generation rates; 2) Tariffs applicable only to bundled customers should be recovered only by bundled customers; 3) Programs created to avoid distribution expenses should be recovered through distribution rates; 4) Programs not falling into other categories should be recovered through distribution rates if available to all customers and does not provide generation-related value; and 5) Cost allocation should correlate with customer benefits.

Marin Clean Energy proposes that "at a minimum, the current policy of automatically assigning virtually all…costs to distribution has to be re-examined and updated since many programs…provide little if any direct distribution-side benefits."[64] Marin Clean Energy also proposes a set of principles that includes, as a basis, competitive neutrality. The principles are summarized as: 1) cost allocation alignment with customer benefits; 2) Programs unavailable to community choice aggregation customers cannot receive cost recovery through distribution rates; 3) Utility programs or tariffs offered simultaneously by community choice aggregation providers cannot receive cost recovery through

[62] DACC/AReM Opening Brief at 2.

[63] DACC/AReM Opening Brief at 6-7.

[64] Marin Clean Energy Opening Brief at 9.

distribution rates; and 4) the cost allocation mechanism is not applicable for demand response programs.

Shell Energy argues that the costs of load modifying programs should be allocated through all customers' distribution rates, unless the program is available solely to bundled customers and unless the program generates resources adequacy credits for the utility. Then the costs should be allocated to bundled customers' generation rates.[65]

In addition, ORA recommends that the Commission should adopt a consistent policy across all three utilities and based on cost causation.

CLECA, PG&E, SDG&E, SCE, and TURN all contend that the current policies regarding cost allocation are equitable and should not be changed.[66] PG&E provides a list of attributes that the Commission should consider when determining an equitable allocation of costs, but maintains that the Commission should conclude that all customers benefit from the utilities' demand response programs and should pay; otherwise, shifting all demand response costs to bundled customers in the generation rate would subsidize direct access and community choice aggregation customers and give direct access and community choice aggregation providers an unfair advantage.[67] PG&E's attributes are: 1) customer eligibility to participate in a demand response program; 2) benefits of the program; 3) cost causation; and 4) equity and fairness. SCE holds that recovering costs only in generation rates does not reflect the benefits of demand

[65] Shell Energy Opening Brief at 10.

[66] *See* CLECA Opening Brief at 2, PG&E Opening Brief at 1, SDG&E/TURN joint Opening Brief at 2, and SCE Opening Brief at 2.

[67] PG&E Opening Brief at 19.

response to all customers and provides examples where the Commission and the Federal Energy Regulatory Commission has determined that the costs of such wide-ranging benefits should be borne by all.[68] SDG&E/TURN jointly assert that because all load sharing entities are not required to procure a proportionate share of demand response but benefit from these programs, the Commission should find that is justifiable to recover the costs for these programs from all load sharing entities' customers.[69] CLECA contends that the Commission should not set allocation based on bifurcation categories because a supply resource provides more benefits than reducing generation needs.[70]

5.1.2. Discussion: Cost Allocation

In determining the appropriate cost allocation, we reviewed the proposed sets of guiding principles suggested by Marin Clean Energy, DACC/AReM, and PG&E. These guiding principles can be condensed into the general guiding principles of cost causation, competitive neutrality, and consistency across utilities, the latter being required by D.12-04-045.[71]

PG&E asserts that cost causation supports allocating demand response program costs to all customers because demand response programs provide grid reliability and all customers use the grid and therefore benefit from grid reliability and demand response programs. This logic would have all customers paying for all utility costs and we do not find that reasonable. PG&E and CLECA present a litany of alleged benefits for demand response that extends beyond

[68] SCE Opening Brief at 4-5.

[69] SDG&E/TURN Opening Brief at 2.

[70] CLECA Opening Brief at 13-16.

[71] DACC/AReM Opening Brief at 4-5, citing D.12-04-045 at 204.

generation. Both surmise that all customers, bundled or unbundled, should pay for demand response programs. DACC/AReM also supports the cost causation principle but argues that these corollary benefits, as discussed by PG&E and CLECA, are not substantiated. Furthermore, DACC/AReM contends that the position of cost causation being equated with customer benefits is unsubstantiated by Commission policy. DACC/AReM insists that cost causation is premised on who imposes the cost.[72]

The Commission has clearly stated that the principle of cost causation means that costs should be borne by those customers who cause the utility to incur the expense, not necessarily by those who benefit from the expense.[73] The interplay between cost causation and benefits, as suggested by CLECA and PG&E, has not previously been adopted by the Commission. DACC/AReM recommends that tariffs which are available and applicable only to bundled customers should have their costs assigned only to those bundled customers.[74] We find this reasonable.

We find it equally reasonable that tariffs and programs, including pilots, available to all customers should be paid for by all customers. Thus, we adopt as a demand response cost allocation principle that any demand response program or tariff, including a pilot, that is available to all customers shall be paid for by all customers and therefore allocated to distribution rates. Likewise, if a program or tariff is only available to bundled customers, that program's costs shall be

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[72] DACC/AReM Reply Brief at 6.

[73] R.12-06-013.

[74] DACC/AReM Opening Brief at 5.

allocated solely to generation rates. This demand response cost allocation principle shall be applied consistently across the three utilities.

We provide two caveats to the demand response cost allocation principle. Marin Clean Energy addressed the issue of competitive neutrality, requesting that the Commission adopt new guidelines where the utilities may not recover costs from community choice aggregation customers for demand response tariffs or programs unavailable to community choice aggregation customers. In adopting the demand response cost allocation principle above, we also begin to address the issue of competitive neutrality. However, in addition, Marin Clean Energy examines the issues of barriers to its ability to develop its own demand response programs and tariffs. Marin Clean Energy explains that it cannot justify creating such programs at ratepayer expense when CCA customers are already being charged for the utility-offered programs. In order to ensure competitive neutrality and the elimination of barriers to direct access and community choice aggregation providers, Marin Clean Energy requests that the Commission prohibit the utilities from recovering costs in distribution rates for any demand response program that is similar to one offered by a direct access and community choice aggregation provider. Furthermore, Marin Clean Energy requests that once a direct access and community choice aggregation provider implements its new program, which is already provided by a utility, within one year the utility discontinue providing the program to the direct access or community choice aggregation providers' customers.

Supporting Parties argue that this position is hypothetical because no community choice aggregation provider offers demand response programs and it is problematic because Marin Clean Energy concurrently requests funding to develop their own program.[75] While we will not authorize funding to Marin Clean Energy to implement its own demand response programs, we acknowledge the barrier to creating such a program. Hence, we adopt the competitive neutrality requirement that once a direct access and community choice aggregation provider begins to offer a demand response program, the competing utility shall discontinue cost recovery from that providers' customers for that or any similar program, no later than one year following the implementation of that program.

In comments to the proposed decision, several parties requested that the Commission order a workshop to determine how to implement the competitive neutrality requirement. We find this request reasonable as there is no record in this proceeding to develop the implementation. The assigned Administrative Law Judge will facilitate a workshop, inviting all interested stakeholders, to determine how to implement the competitive neutrality requirement.

5.2. Phase Two: Use of Backup Generation

This decision confirms a policy statement that the use of backup generation in demand response programs is antithetical to the Energy Action Plan and the Loading Order. As indicated below, the Commission has jurisdiction over the use of ratepayer funds and whether these funds should be used to protect the environment or purchase fossil-fueled generation for the demand response programs. We have issued several decisions have several proceedings pending

[75] Supporting Parties Reply Brief at 5.

with regard to greenhouse gas amelioration.[76] However, we conclude that the record is incomplete to make a determination of whether it is prudent to prohibit their use in demand response programs at this time.

Additionally, we find that we should first ascertain the depth of this issue by determining the number of BUGs being used and the extent to which they are being used. Therefore, as further described below, we direct the utilities to collect information regarding the use of BUGs and file the data in this proceeding. The results of the data will determine the next steps.

5.2.1. Background: Use of Backup Generation

D.11-10-003 states that "we will adopt as a policy statement, the Energy Division proposal that any demand response program, whether operated by an [investor owned utility] or a non- [investor-owned utility], that uses backup generation for demand reduction should not count towards [resource adequacy] obligations for any Commission-jurisdictional Load Serving Entity."[77] D.11-10-003 required the utilities to work with Commission staff to identify data on how customers intend to use backup generation, and to identify the amount of demand response provided by backup generation when enrolling new customers in the demand response programs or renewing demand response contracts. Furthermore, the decision deferred the details on the process evaluation to the utilities' 2012-2014 applications in Applications (A.) 11-03-011 et al. As pointed out by the Joint Demand Response Parties, D.11-03-011 did not include an

[76] *See*, e.g. D.08-10-037 (adopting greenhouse gas regulatory strategies; D.07-09-017 (regarding reporting and verification of greenhouse gas emissions in the electricity sector); R.13-12-101 (Long-Term Procurement proceeding, which includes greenhouse gas-related issues; and R.11-03-012 (greenhouse gas auction revenue proceeding.)

[77] D.11-10-003 at 29.

ordering paragraph adopting the policy statement quoted above. Rather, Ordering Paragraph 3 directed the utilities to begin a data collection process on the use of backup generation.[78]

D.12-04-045, which addressed the applications in A.11-03-001 et al., recognized that some customers rely on the use of backup generation to provide their committed load reduction. But the decision found it unclear whether using backup generation in the Base Interruptible Program is permitted under the Federal, State or local air quality regulatory agencies' rules. Concluding that the record of A.11-03-001 et al. did not contain sufficient information to make a determination, D.12-04-045 deferred all issues related to backup generation to R.07-01-041 or its successor proceeding.

The OIR for R.13-09-011 inadvertently omitted the issue of backup generation. However, the issue of backup generation was discussed at the pre-hearing conference[79] for this proceeding and included in both the original Scoping Memo and the revised Scoping Memo. Parties addressed this issue during the June Workshops and presented their arguments in opening and reply briefs.

As discussed below, party opinions for the use of backup generation generally fall into two categories: a) regulating the use of backup generation is not in the jurisdiction of the Commission, but rather the California Air Resources Board and local air quality management districts;[80] or b) the Commission has

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[78] D.11-10-003, Ordering Paragraph 3 at 34.

[79] Prehearing Conference Transcript at 55.

[80] Parties supporting this opinion include DACC/AReM (Opening Brief at 19), SCE (Opening Brief at 7-8), CLECA at 4, PG&E (Opening Brief at 24), and SDG&E (Opening Brief at 2).

already concluded that it "should" prohibit backup generation for demand response.[81]

5.2.1. Discussion: Use of Backup Generation

There are four questions before us regarding the use of backup generation: 1) What is the Commission's current policy regarding the use of backup generation in demand response programs; 2)Whether the Commission has the jurisdiction to determine whether demand response programs should allow the use of backup generation; 3) If the Commission has jurisdiction, whether it should allow the use of backup generation; and 4) If the Commission has jurisdiction, is there a need to collect additional data to determine whether the Commission should allow the use of backup generation.

We first focus on the issue of current policy for backup generation in demand response. In response to the Joint Demand Response Parties and Direct Access Customer Coalition's assertion that the Commission has not adopted a policy on the use of backup generation, NRDC and Sierra Club present a historical timeline of Commission decisions regarding backup generation as shown in the following table.

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[81] Parties supporting this opinion include NRDC/Sierra Club (Opening Brief at 2) and ORA (Opening Brief at 14). These two parties differ in how to implement such a policy. NRDC/Sierra Club recommends that the utilities should collect data on the use of BUGs and ORA recommends that the use of backup generation should be strictly prohibited and penalized.

TABLE 5 Historical Policy Regarding the Use of Backup Generation in Demand Response[82]	
D.03-06-032, R.02-06-001, California Demand Response: A Vision for the Future.	The three main objectives for demand response include reliability, lower power costs, and environmental protection. "the Agencies' definition of demand response does not include or encourage switching to the use of fossil fueled emergency backup generation, but high-efficiency, clean distributed generation may be used to supply on-site loads."[83]
Energy Action Plan (2003).	Proposed specific actions to ensure that adequate, reliable and reasonably priced electric power and natural gas supplies are achieved and provided through policies, strategies and actions that are cost-effective and environmentally sound.
D.05-01-056 Approving the 2005 Demand Response Programs and Budgets.	In denying PG&E's requested backup generation program, the Commission stated that the program was denied "because it promotes reliance on diesel generators as part of California's resource mix, in contrast to the Energy Action Plan's loading order preference."
D.06-11-09.	In denying PG&E's request to fund a retrofit of exiting customer-owned diesel backup generation, the Commission stated that, "our objective in funding demand response programs is to reduce system demand, not to substitute system electricity with electricity generated by off-grid natural gas facilities...We therefore deny PG&E's request to initiate a Backup Generation program.[84]

[82] Sierra Club and NRDC Opening Brief at 6-8.

[83] D.03-06-032, Attachment A at 2.

[84] D.06-11-049 at 58.

TABLE 5 Historical Policy Regarding the Use of Backup Generation in Demand Response[82]	
Energy Action Plan (2008).	In establishing the Loading Order, the Plan describes cost-effective demand response and energy efficiency as the top of the loading order followed by renewable resources, and only then in clean conventional electricity supply.[85]
D.09-08-027.	In rejecting a proposal by Blue Point Energy to recognize backup generation as demand response, the Commission stated that "as a policy matter, we have already found that subsidizing backup generation with demand response funds is not appropriate; we prefer to reserve these funds for activities that reduce total energy use."[86]
D.11-03-003.	The Commission stated that, "we do not want to allow fossil-fueled emergency backup generation to receive system or local [resource adequacy] credit as demand response resources…we have consistently stated that demand response programs that rely on using backup generation were contradictory to our vision for demand response and the Loading Order."[87]

The Joint Demand Response Parties contend that ORA, the Sierra Club and NRDC and documents in this rulemaking have misstated the adopted policy on backup generation for demand response. As correctly pointed out by Joint Demand Response Parties, the referenced policy statement in D.11-10-003, was not included in an ordering paragraph and has not been implemented.[88] Hence,

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[85] State of California, Energy Action Plan, 2008 Update, February 2008.

[86] D.09-08-027 at 164-166.

[87] D.11-10-003 at 26.

[88] Joint Demand Response Parties Opening Brief at 9.

no demand response customer currently using a fossil-fueled backup generator is out of compliance with D.11-10-003. However, D.11-10-003 clearly adopted a policy statement as stated in both the discussion and a conclusion of law. Because the statement was not included in an ordering paragraph does not make it "mere surplusage." It is a settled rule of legal interpretation to avoid rendering particular terms as meaningless or mere surplusage.[89] The Joint Parties argue that none of the statements referenced above by Sierra Club and NRDC is true today regarding existing Commission policy and none represent an appropriate policy, without qualification, for demand response programs going forward.[90] We disagree. The Commission has made the Energy Action Plan and the Loading Order accepted policy of the highest importance. As such, while we agree that the Commission has not yet implemented a policy prohibiting the use of fossil-fueled backup generation for demand response programs, it has certainly made clear its preference for cleaner technologies.

We now address the issue of whether the Commission has the jurisdiction to make a determination on whether the use of backup generation should be permitted in demand response programs. CLECA argues that federal, state and local air quality agencies have clear jurisdiction over backup generation and the Commission does not.[91] SCE points to Cal. Health & Safety Code Section 4000, which states that "local and regional authorities have the primary responsibility for control of air pollution from all sources, other than emissions from

[89] *See, e.g., City of San Jose v. Superior Court*, 5 Cal. 4th 47, 55 (1993).

[90] *Id.* at 10.

[91] CLECA Opening Brief at 7, citing SCE-02 at 17.

automobiles.[92] Both CLECA and SCE surmise that the Commission should recognize and defer the regulation of backup generation to those agencies entrusted with air quality.[93] Furthermore, CLECA cautions the Commission that while its jurisdiction is broad, it is not unlimited, and that the court has been clear that the delegation of jurisdiction over air quality issues is to the air quality agency.[94] The Joint Demand Response Parties assert that the jurisdictional role and impact of air quality regulations on the use of backup generation cannot be ignored.[95]

In reviewing the Commission's past statements regarding the use of backup generation for demand response, we affirm that the Commission has continuously endeavored to ensure that "adequate, reliable and reasonably priced electric power and natural gas supplies are achieved and provided through policies, strategies and actions that are cost-effective and *environmentally sound*," as required by the California Energy Action Plan. As such, our previous statements regarding backup generation have addressed an aversion to the use of technologies, such as fossil-fueled backup generation, that are antithetical to the efforts of the Energy Action Plan and the Loading Order.

The Supporting Parties contend that the Commission's jurisdiction is only achievable for participants of the utility-administered demand response programs and, therefore, the limited jurisdiction makes it impossible for the

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[92] SCE Opening Brief at 7-8.

[93] CLECA Opening Brief at 7 and SCE Opening Brief at 8.

[94] CLECA Opening Brief at 6-7 citing Public Utilities Code Section 701 and *Orange County Air Pollution Control Dist. v. Public Util. Com.* (1971) 4 Cal. 3d 945,953; 95 Cal.Rprt. 17.

[95] Joint Demand Response Parties Opening Brief at 17.

Commission to effectively regulate the use of backup generation by all demand response participants.[96] Furthermore, the Supporting Parties contend the Commission does not have the jurisdiction over third-party demand response providers when they are not operating under contract to the regulated utilities.[97] As noted by CLECA, Public Utilities Code Section 701 provides the Commission with broad authority. Furthermore, Public Utilities Code Section 701.1 states that, in addition to other ratepayer protection objectives, a principal goal of resource planning is to *improve the environment* (emphasis added). At this time, we conclude that the Commission has the authority to regulate the use of backup generation by any participant of a Commission–regulated demand response program.

Further, applicable law supports the conclusion that the Commission has jurisdiction to bar fossil-fueled BUGs. Senate Bill (SB) 1414 (Public Utilities Code Section 380, 380.5) sets forth, as one of California's objectives for resource adequacy requirements, "establishing new or maintaining existing demand response products and tariffs that facilitate the economic dispatch and use of demand response that can either meet or reduce an electrical corporation's resource adequacy requirements." The statute makes clear that efforts to incorporate demand response into the state's resource adequacy program should also reduce greenhouse gas emissions. Section 1(b) of SB 1414 provides "(b) In enacting this act, it is the intent of the Legislature to ensure that California and the Public Utilities Commission *help meet the state's greenhouse gas emissions reduction goals* and achieve electrical grid reliability by increasing the utilization

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[96] Supporting Parties Reply Brief at 4.

[97] *Ibid.*

of demand response." (Emphasis added.) Likewise, the statute makes clear that it was not intended to hinder efforts at greenhouse gas reduction: Section 1 (c) provides that, "It is further the intent of the Legislature, in enacting this act, to ensure that the procurement, programmatic, tariff-based, and other options that the Public Utilities Commission is pursuing or may pursue in furtherance of demand response *are in no way hindered or superseded by the provisions in this act.*" (Emphasis added.)

Federal law does not preempt the Commission's action to bar fossil-fueled BUGs. In a document summarizing its response to comments on the federal Environmental Protection Agency's (EPA) national emissions standards for hazardous air pollutants from stationary sources,[98] the EPA made clear that it did not intend to preempt more stringent state requirements:

> [T]the EPA's stationary source regulations do not act to preempt more stringent state or local measures. States that believe it is more appropriate to regulate the use of stationary emergency engines more stringently than the EPA are free to do so. The EPA's regulations under section 111 and 112 apply nationally, so it is appropriate that areas with more serious pollution concerns regulate in a more stringent manner than what may be appropriate nationally." Response to Comments at 15.

Thus, the Commission's action to bar fossil-fueled BUGs both furthers the intent of SB 1414 and meets the EPA's stationary source requirements.

In regards to whether the Commission should regulate the use of backup generation by Commission-regulated demand response programs, several parties

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[98] The document appears here: http://www.epa.gov/ttn/atw/icengines/docs/20140801responsetocomments.pdf) (Response to Comments).

assert that it is premature and/or there is not sufficient evidence in the record.[99] CLECA and PG&E add that the Utilities should not be required to collect information on the use of backup generation by demand response customers. PG&E argues that it is more appropriate for third party providers to collect the usage information from its customers, stating that the utilities do not have the knowledge, expertise or resources to collect the air quality data or understand air quality permit conditions.[100] CLECA asserts that the Commission should not increase the reporting burden on customers beyond what is required by air quality regulators.[101]

We agree that there is insufficient evidence in the record to determine whether it is prudent to prohibit backup generation. In D.11-10-003, the Commission directed the utilities to work with the Energy Division to identify data on how customers intend to use backup generation and identify the amount of demand response provided by BUGs.[102] The Utilities have not complied. Thus, this research has not been completed.[103]

In reply briefs, the Supporting Parties note that there is not a clear picture of how prevalent the use of backup generation is by demand response participants.[104] Before we determine whether it is prudent to regulate the use of

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[99] *See*, for example, PG&E Opening Brief at 22-24, Supporting Parties Reply Brief at 5-6, Joint Demand Response Parties at 5-6, DACC/AReM Opening Brief at 18, and NRDC/Sierra Club Reply Brief at 6.

[100] PG&E Opening Brief at 25.

[101] CLECA Opening Brief at 9.

[102] SCE Opening Brief at 10 and Joint Demand Response Parties Opening Brief at 9 and 10.

[103] Joint Demand Response Parties Opening Brief at 12.

[104] Supporting Parties Reply Brief at 4.

backup generation by demand response participants, we should not only determine the size of the issue but we should obtain the information that we previously requested. Thus, as recommended by the NRDC and Sierra Club, we take an initial step of requiring that each contracted demand response participant self-certify whether they own or operate a backup generator and, if they do, provide the make, model and location of the generator.[105] This information shall be collected by the Utilities over the course of 2015 and shall be filed as a compliance document in this proceeding no later than November 30, 2015. Furthermore, we require the Utilities to collect information about hourly usage information for each of the BUGs owned by customers that participate in their programs. In comments to the proposed decision, SCE argued that some owners of BUGs don't have hourly data because of the non-existence of requisite meters to record this information. We do not require the installation of sub-meters to collect this data, as there is no funding for the meters. Hence, we only require the collection of this data from customers who have it but record which owners do not have the meters.

For those customers with the requisite meters, the Utilities are to map the collected data against their demand response events and the load reductions provided by the participants so that we are able to determine the extent to which backup generation is used coincident with demand response events and how that usage compares against the load drop provided by the participant. This information shall be collected over the course of 2015 and shall be filed as compliance document in this proceeding no later than November 30, 2015.

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[105] *See* NRDC/Sierra Club Opening Brief at 6.

In comments to the proposed decision, SDG&E expressed concern regarding the number of residential customers in Demand Response programs requiring data collection. We recognize that both SDG&E and SCE have thousands of customers participating in Peak Time Rebate. Thus, at this time, we exempt residential customers from this data collection requirement.

Additionally, SCE noted that tariff changes are necessary to ensure participant compliance with the Utilities' data requirements. Thus, the Utilities shall file, within 60 days of the issuance of this decision, a Tier One advice letter making appropriate changes to the tariffs.

5.3. Phase Three: Should the DRAM be the Preferred Means for Procuring Demand Response Supply Resources?

The Settling Parties propose that during the time that issues regarding the DRAM are being resolved through the public working group, the Commission should embark upon a pilot of the DRAM. As discussed above, the Settlement provides a path toward implementation of the pilot and eventually the full implementation of a procurement mechanism. While the Settling Parties agreed on the path toward implementation, they could not reach agreement on 1) whether the final procurement mechanism implemented by the Commission should be the preferred means for procuring demand response supply resources or 2) how to encourage participation in the Pilot. Parties provided opening and reply briefs on these two issues.

As described below, we find that until a final procurement mechanism is adopted by the Commission, it is premature to determine whether this mechanism should be the preferred means for procuring demand response resources. Furthermore, we want to ensure that all current demand response megawatts continue to be available in the future, but we want to also ensure that the DRAM pilot has a fair opportunity to succeed. We agree with TURN that establishing set-asides for each utility's DRAM pilot auction would strike a balance between providing a reasonably-sized market and enabling current procurement mechanisms to continue. We assign this task, as further described below, to the DRAM pilot design working group.

5.3.1. Overview: DRAM as the Preferred Procurement Mechanism and Encouraging DRAM Pilot Participation

In briefs, parties presented views on 1) whether the DRAM should be the preferred method of supply resource procurement and 2) how the Commission should encourage participation in the DRAM pilot.

We first provide an overview of the issue of whether the DRAM should be the preferred method of procurement. Parties were divided into two opinions: a) the DRAM should be the sole method of procurement; and b) it is premature to make a determination on this issue.

ORA supports the position that the DRAM should be the preferred method for procuring supply resource demand response. ORA asserts that currently the only alternative to the DRAM is the Aggregator Managed Portfolio (AMP) program because it can be modified to integrate into CAISO markets as supply resources.[106] ORA contends that in comparison, the current AMP model of procurement does not ensure ample competition among demand response providers, the lowest prices for ratepayers, or reliable performance.[107] ORA concludes that these limitations should lead the Commission to support the

[106] ORA Opening Brief at 5.

[107] ORA Opening Brief at 7.

DRAM as the preferred procurement mechanism. TURN also supports the idea that DRAM could be the preferred method for procurement but believes this issue "will be better addressed after the DRAM Pilot auctions are conducted."[108]

In opposition to ORA, several parties (CLECA, Joint Demand Response Parties, PG&E, SDG&E and SCE) consider it premature to designate the DRAM as the preferred method of procurement. Similar to TURN, CLECA contends that this issue should be determined by the experience of the pilot.[109] SCE also agrees that the Commission should explore the efficacy of the pilot but contends that it is unnecessary to assign such limitations given the untapped demand response potential that the DRAM could explore.[110] PG&E asserts that there is no evidence that the DRAM should be the preferred means of procurement, especially given the concern regarding the market uncertainties and DRAM procurement.[111]

Regarding the issue of encouraging participation in the DRAM pilot, here again, party positions were aligned on two sides: 1) the Commission should prohibit any limitations to demand response programs as a means to encourage participation in the DRAM, and 2) the Commission should encourage participation in the DRAM by implementing limitations either on program(s) or through another means.

CLECA, Joint Demand Response Providers, PG&E, SDG&E, and SCE oppose any limitations placed on demand response programs for the purpose of

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108 TURN Opening Brief at 7.

109 CLECA Opening Brief at 17.

110 SCE Opening Brief at 12-13.

111 PG&E Opening Brief at 29-30.

encouraging participation in the DRAM pilot. SCE cautions that such limitations could jeopardize current programs by reducing overall participation.[112] Joint Demand Response Parties contend that there is no record to support restrictions on demand response programs for the purpose of encouraging participation.[113] PG&E recommends that in lieu of limitations, the Commission should focus on the design of the pilot and ensure that it includes mechanisms to encourage participation such as the outreach and recruitment effort seen in a current pilot dealing with the CAISO market and third parties.[114]

ORA and TURN argue that the Commission should adopt mechanisms to encourage participation in the DRAM pilot. TURN explains that the challenge to making the DRAM pilot a meaningful test of the DRAM concept is the fact that much of the potential incremental demand response may by procured by other means such as the utilities' requests for offers with much more attractive terms than a competitive auction.[115] TURN recommends that the Commission establish set asides for the two auctions defined by location, customer class or attribute, or end uses.[116] ORA recommends that because the AMP program contracts are the closest alternative to the DRAM, the Commission should restrict the number of MW procured through the AMP program contracts.[117]

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[112] SCE Opening Brief at 12 and 16.

[113] Joint Demand Response Parties Opening Brief at 24.

[114] PG&E Opening Brief at 31.

[115] TURN Opening Brief at 8.

[116] TURN Opening Brief at 9.

[117] ORA Opening Brief at 7 and 10.

5.3.1. Discussion: DRAM as the Preferred Procurement Mechanism and Encouraging DRAM Pilot Participation

The Revised Scoping Memo included, as one of the issues in this proceeding, the design, pilot and implementation of a procurement mechanism for bidding demand response supply resources into the CAISO market. As such, the Settling Parties have agreed to the development of such a mechanism based, in part, on a piloting of the DRAM. While the Commission would prefer to fully implement a mechanism now, we have affirmed that there are complexities—both technical and otherwise, which lead us to move forward in a more measured approach, as suggested by the Settling Parties.

Only ORA recommends that the Commission adopt in this decision a policy that the DRAM is the preferred procurement mechanism for bidding supply resources into the CAISO market. ORA contends that by including a DRAM proposal in its rulemaking the Commission has indicated that DRAM will play a crucial part in shaping the Commission's future procurement policy for demand response.[118] However, as shown by the Joint Demand Response Parties, the DRAM is only a "good starting point for exploration and discussion" as a means to increase demand response in the CAISO markets.[119] As noted by PG&E, there is no record in this proceeding regarding the effectiveness of the DRAM, hence the reason for moving forward with a DRAM pilot.[120]

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118 ORA Reply Brief at 5.

119 Joint Demand Response Parties Opening Brief at 25 quoting form D.14-03-026 at 27.

120 *See* PG&E Opening Brief at 26, stating that "the DRAM is a new and untested concept" and at 30, stating that "there is no evidence that the DRAM should be a preferred means of procuring supply resources…the evidence indicates concerns."

We confirm that one of the outcomes of this proceeding is to adopt a procurement mechanism for bidding supply resources into the CAISO market. If the DRAM pilot is successful, the DRAM could become one of several procurement mechanisms or the sole mechanism. But, we cannot make that determination at this point. The first step is to see if the pilot is feasible and whether it is successful. We conclude that it is not reasonable to adopt a preferred mechanism for bidding supply resources into the CAISO market when no mechanism has been tested for feasibility or success.

We now turn to the issue of ensuring adequate participation in the DRAM pilot. ORA and TURN caution that, aside from the technical challenges for the DRAM, the pilot is at a disadvantage for attracting participation. ORA states that there is only a small sub-set of demand response customers who can currently meet the stringent CAISO tariff and the DRAM's proposed resource adequacy requirements. ORA surmises that there has to be a very large universe of customers available for meeting the minimum goal of 10 MW to 20 MW for each of the two auctions. As a result, ORA contends that unless the Commission ensures sufficient MWs of eligible customers available, the DRAM pilot will fail without reaching a conclusion regarding efficacy.[121] Additionally, TURN maintains that mechanisms such as the AMP program agreements may offer more attractive terms to demand response providers in comparison to a competitive auction, and thus result in a "crowding out" effect.[122] Both ORA and TURN recommend that the Commission adopt provisions to provide a level playing field for the DRAM pilot.

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[121] ORA Opening Brief at 9.

[122] TURN Opening Brief at 8.

First, SCE states that these restrictions are unnecessary given that there is still untapped demand response potential that the DRAM pilot could explore.[123] We question this statement given that SCE previously stated that there are finite groups of demand response participants.[124] Additionally, SCE expressed concern regarding a pattern of frequent migration by customers from one demand response alternative to another.[125] SCE's concern about a lack of demand response customers led to the discussion of pursuing a demand response potential for setting goals. We, therefore, cannot dismiss as unnecessary ORA and TURN's request for a level playing field based on the number of available customers when that number is unknown at this time.

Second, several parties contend that restrictions in the current demand response programs could lead to decreases in participation and therefore impact the ability of the Utilities to reach the aspirational goal discussed in the Settlement. However, no party provides evidence of such decreases, only a supposition that limitations could lead to decreasing participation. Thus, we cannot discount ORA and TURN's position based on an unsupported alleged decrease in overall participation.

Third, Joint Demand Response Parties claim that there is no basis to assume such restrictions will benefit either the DRAM pilot or current programs.[126] Joint Demand Response Parties contend that if the DRAM pilot is

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[123] SCE Opening Brief at 12.

[124] June Workshop Report at II.F.1.a and II.F.3.

[125] June Workshop Report at II.F.1.a.

[126] Joint Demand Response Parties Opening Brief at 24.

well designed and structured, it should encourage customer participation.[127] PG&E agrees, and suggests that the design of the DRAM pilot could include a direct mechanism to encourage participation.[128] PG&E further suggests that the DRAM pilot could use a prior PG&E pilot as an example of a significant outreach and recruitment effort.[129] ORA disputes this recommendation, noting that the findings of the pilot in question, the IRM2,[130] concluded that non- investor owned utility load shedding entities have been reluctant to support their customers' participation in the IRM2.[131] We agree that we cannot rely solely on restrictions to ensure positive outcomes in either the DRAM pilot or current programs. However, the Commission should ensure that the DRAM pilot has an opportunity to be tested.

Looking at the TURN and ORA request to provide a level playing field for the DRAM pilot, we look again at TURN's statement that "other mechanisms may offer more attractive terms to demand response providers than a competitive auction and therefore some measures to provide the DRAM pilot a reasonably-sized test market are likely necessary for a meaningful pilot."[132] The Commission has previously stated its desire to implement a competitive

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[127] Joint Demand Response Parties Opening Brief at 25.

[128] PG&E Opening Brief at 31.

[129] PG&E Opening Brief at 31.

[130] IRM2, Intermittent Resource Management Phase 2, observed whether a properly controlled demand side resource can respond appropriately to CAISO needs and provide real-time five-minute energy services. *See* D.12-04-045 at footnote 338.

[131] ORA Reply Brief at 3.

[132] TURN Opening Brief at 8.

mechanism for bidding supply resources into the CAISO market.[133] While we acknowledge that a final mechanism may evolve to become something other than the pilot or even the DRAM, we find it reasonable to ensure a level playing field for this pilot. It is not possible to measure the pilot's success or even feasibility when it has limitations on participation. Given that we do not know the potential of demand response and will not know the results of the study for at least 18 months, we find it reasonable to provide the DRAM pilot a reasonably-sized market for test purposes.

ORA recommends imposing limitations on the AMP program to ensure participation in the DRAM pilot. However, we agree with the Joint Reply Brief of SCE, PG&E, CLECA and the Joint Demand Response Parties that using DRAM to mount a collateral attack on one demand response program is inappropriate.[134] Instead we find TURN's suggestion to create set-asides to tackle the crowding out effect to be a reasonable manner to create a level playing field for the DRAM pilot. TURN recommends looking at the variables of location, customer class or attribute, and end-uses. We further agree with TURN that there is nothing in the record for the Commission to determine a final set-aside. We therefore direct the working group assigned to develop the design of the DRAM pilot to also recommend to the Commission a proposal for a set-aside based upon location, customer class or attribute, or end uses. The set-aside proposal shall be included with the working group's April 1, 2015 report. As with the DRAM pilot itself,[135]

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[133] Revised Scoping Memo at 5.

[134] Supporting Parties Reply Brief at 10.

[135] Settlement at 24: This DRAM Pilot will not set precedent for future procurement of Supply Resources.

the set-asides should not be construed as setting precedent in the final procurement mechanism adopted by the Commission.

6. Comments on Proposed Decision

The proposed decision of the Administrative Law Judge in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. The Judge permitted parties to separately file comments on the Settlement and the litigated issues.[136] Comments on the Settlement were filed on November 17, 2014 by the Settling Parties and Calpine and replies were filed on November 24, 2014. Comments on the litigated issues were filed on November 17, 2014 by CLECA, DACC/AReM, Joint Demand Response Parties, Marin Clean Energy, ORA, PG&E, SDG&E, SCE and TURN. Reply comments on the litigated issues were filed on November 24, 2014by DACC/AReM, Joint Demand Response Parties, Marin Clean Energy, ORA, PG&E, and SCE. In response to comments to the proposed decision, corrections and clarifications have been made throughout this decision.

In the Motion to approve the Settlement, the Settling Parties requested that the Commission authorize the three Utilities to convene workshops, *prior to a final decision* (emphasis added), to enable parties and all interested stakeholders to begin working together promptly to design and develop the materials and criteria necessary for the DRAM pilot.[137] The Settling Parties contend that an early start to this working group, prior to a final decision on the approval of the

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[136] Administrative Law Judge Ruling issued on November 6, 2014. *See* also Ruling issued on November 19, 2014 increasing page limit.

[137] Motion at 3.

Settlement, is necessary to timely commence the DRAM pilot.[138] During a prehearing conference, the Settling Parties noted that anti-trust regulations would require this authorization so that the three Utilities would not be seen as taking advantage of their monopoly status.[139] In comments to the proposed decision, the Settling Parties state that the Ruling requested in the Motion has not been issued and there is no certainty that there will be sufficient time for an initial auction to be held in 2015.

A Ruling addressing this request was not nor should it have been issued. It would not have been appropriate for a Ruling approving this working group to be issued, either by a Judge or an assigned Commissioner. Such a Ruling could be construed as pre-judging the outcome of the Motion.

The Proposed Decision while approving a modified Settlement—including the approval of a working group for the design of the DRAM, did not specifically authorize the Utilities to work together. Hence we have now included language in the decision addressing this topic, and have added an ordering paragraph.

7. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Kelly A. Hymes is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. No party opposed the terms and conditions of Issue Area 1 of the Settlement.

[138] Motion at 20.

[139] TR, Vol. 3 at 163, lines 19-24. *See also* TR, Vol. 3 at 173-174.

2. Commission staff is currently working on a contract for a consultant to study demand response potential and needs.

3. Studying the potential of demand response in the Utilities' service areas will assist the Commission in setting future goals for demand response based on potential, needs, and value.

4. The Commission has previously authorized the funding for a study on demand response potential, reducing the timeline to implement the study for the purposes of this proceeding.

5. The consultants for a demand response potential study have already been selected, reducing the timeline to implement the study.

6. The Commission should be prudent in its time management of reaching resolution on the issues in this proceeding.

7. Issue Area 1 of the Settlement does not set a specific future goal for demand response.

8. Issue Area 1 of the Settlement sets forth a process to lead the Commission to a determination of specific future goals for demand response.

9. Current Commission policy does not include emergency or reliability demand response programs toward the attainment of the five percent goal that was established in the Energy Action Plan and in D.03-06-032.

10. The Settlement provides no justification as to why emergency or reliability demand response programs should now be included as part of the interim goal.

11. Categorization of demand response programs is not adequately addressed in Issue Area 2 of the Settlement.

12. Until the results of the Study and the outcomes of the Working Groups are available, the Commission does not have enough information to determine

whether and how a program can be categorized into both Supply and Load Modifying resources.

13. In D.14-03-026, the Commission determined that bifurcation of the demand response programs would begin in 2017.

14. Bidding demand response into the CAISO market has been an objective of the Commission since 2007.

15. Bidding demand response into the CAISO market is a complex process based on multiple factors.

16. Calpine's concern regarding maintaining the current counting method through 2019 is valid.

17. In D.14-03-026, the Commission confirmed that setting resource adequacy capacity for demand response has been and will continue to be resolved in the resources adequacy proceeding.

18. The Revised Scoping Memo requires that this proceeding identify the concerns regarding resource adequacy, determine the cause of those concerns, and provide recommendations to resolve them.

19. The Settlement recommends that the Valuation Working Group provide recommendations to resolve the concerns regarding resource adequacy.

20. There is little justification for delaying, until 2020, use of a more accurate treatment of demand response resources for resource adequacy purposes.

21. Recommendations of the Valuation Working Group are due by May 1, 2015.

22. Delaying a more accurate accounting of demand response's contributions toward meeting resource adequacy requirements nullifies an important purpose of bifurcation.

23. 2020 is not a reasonable timeline for full implementation of integration into the CAISO energy market.

24. Resource adequacy policy developed in R.14-10-010 and its successor proceeding should flow through to demand response resources as it is developed.

25. Full bifurcation of demand response includes: 1) adoption and implementation of an appropriate methodology to value and account for load modifying resources; 2) adoption of rules regarding the resource adequacy treatment for demand response resources; 3) adoption and implementation of requirements to integrate demand response into the CAISO market; and 4) adoption of the categorization of demand response programs.

26. The terms and conditions of Issue Areas 2 and 4 do not distinctly address the actual categorization of current programs.

27. The 2017-2019 demand response program cycle will be a transitional cycle.

28. The transition program cycle should end with a complete transition to full implementation of bifurcation..

29. Parties in this proceeding have expertise in demand response issues.

30. The hiring of additional experts for the Valuation Working Group may be necessary.

31. The record of this proceeding includes little evidence to justify the statement that demand response programs can be partitioned into load modifying and supply resources in the future.

32. The Commission has limited staff resources and those resources may not be available to participate in every working group meeting proposed by the Settlement.

33. Piloting the Demand Response Auction Mechanism was first recommended by Commission staff during the June workshops.

34. A pilot would allow the details of an auction mechanism to be refined with experience.

35. The Commission has previously approved the use of a pilot many times over the lifetime of the demand response program.

36. A pilot is a cost-effective way of implementing an idea, learning from that idea, and making changes to improve its success.

37. The record in this proceeding highlights the complexity of the CAISO market integration.

38. A two-year pilot of the DRAM is a prudent approach to learning from experience while simultaneously increasing our understanding of the CAISO complexities through the Settlement-proposed working groups.

39. The pilot will not reduce the role of DRAM as a means of securing supply resources.

40. The pilot will ensure that the Commission takes the appropriate steps to making the DRAM a successful means to procure supply resources.

41. Issue Area 3 of the Settlement does not adequately address the issues of whether it is possible for third party demand response providers to play a much larger role in the procurement of demand response supply resources.

42. Solely addressing the role of the utilities as it relates to DRAM does not capture the entirety of the utility role issue.

43. The issue of whether the Utilities should play a supporting role versus a central role remains unresolved.

44. The State Action Doctrine affords private entities protection from antitrust liability when they act pursuant to state policy and under the direct supervision of an agency such as the Commission.

45. No party opposed the terms and conditions of Issue Area 5 of the Settlement.

46. The Settling Parties lay out a course for reviewing and making determinations on future budget cycles through a collaborative effort that balance the issues of regulatory certainty, flexibility to terminate underperforming programs or bring online new programs, and ensuring cost-effectiveness based on best-available data.

47. R.13-09-011 will still be active when the Utilities are preparing their applications for the 2017-2019 demand response portfolios.

48. End-of-year review workshops should ensure that each successive year of the transitional cycle moves the Commission toward improved CAISO market integration and bifurcation implementation.

49. The Settling Parties have complied with the provisions of Commission Rules of Practice and Procedure (Rule) 12 regarding Settlements.

50. The multiple tasks outlined in the Settlement are aligned with the intent of R.13-09-011 including to enhance the role of demand response in meeting the State's long-term energy goals while maintaining system and local reliability.

51. The Utilities will submit 2017-2019 demand response program applications with new or redesigned programs, which should have the characteristics necessary to meet specific pre-determined needs either as a load modifying or supply resource; this complies with the bifurcation requirement in D.14-03-026.

52. Complete implementation of bifurcation cannot occur until resource adequacy issues have been resolved.

53. The Settlement continues the resolution of resource adequacy issues through the efforts of the Integration Working Group.

54. Because the integration into the CAISO market is complex, the complete resolution process will take more time than previously anticipated and later than 2017.

55. In D.14-03-026, the Commission did not order that full implementation of bifurcation require that only supply resources receive resource adequacy credit.

56. The Settlement puts the Commission on a solid path toward the resolution of Phase Three issues and another step closer to direct participation of demand response into the CAISO market.

57. By representing diverse interests including residential and large energy customers, third party demand response providers, community choice aggregation providers, direct access providers, environmental organizations, and utilities, the Settling Parties balance the various interests at stake.

58. The Settlement strives to balance the interests of the various stakeholders while enhancing the role of demand response in California.

59. The Settlement should result in a portfolio that provides reductions in peak electricity consumption, ratepayer savings through the avoidance of new generation construction and reduced greenhouse gas emissions.

60. The guiding principles recommended by the parties for cost allocation can be condensed into the general guiding principles of cost causation, competitive neutrality, and consistent across the utilities.

61. PG&E's assertion, that demand response programs provide grid reliability and because all customers use and benefit from the grid all customers should pay for demand response programs, would result in all customers paying for all utility costs.

62. The principle of cost causation means that costs should be borne by those customers who cause the utility to incur the expense.

63. The Commission has not adopted any statement or policy that creates an interplay between cost causation and benefits.

64. We recognize that there is a barrier for direct access and community choice aggregation providers implementing their own demand response programs.

65. There is insufficient evidence in the record to determine how to implement the competitive neutrality portion of the cost causation principle.

66. D.11-10-003 did not include in an ordering paragraph, and therefore, did implementation a prohibition of the use of fossil-fueled backup generation in demand response programs.

67. No demand response customer currently using a fossil-fueled backup generator is out of compliance with D.11-10-003.

68. The Commission has made the Energy Action Plan and the Loading Order accepted policy at the highest level.

69. The Commission has made clear its preference for cleaner technologies.

70. The Commission has not attempted to regulate emissions.

71. The Commission has continuously endeavored to ensure that adequate, reliable and reasonably-priced electric power and natural gas supplies are achieved and provided through policies, strategies, and actions that are cost-effective and environmentally sound.

72. The Commission's previous statements regarding backup generation have addressed an aversion to the use of technologies, such as fossil-fueled backup generation, that are antithetical to the efforts of the Energy Action Plan and the Loading Order.

73. There is insufficient evidence in the record of this proceeding to determine whether it is prudent for the Commission to prohibit the use of fossil-fueled backup generation in demand response programs.

74. D.11-10-003 directed the utilities to work with the Energy Division to identify data on how customers intend to use backup generation and identify the amount of demand response provided by backup generation.

75. The data collection directed by D.11-10-003 has not been completed.

76. Prior to determining whether it is prudent to prohibit the use of backup generation in demand response, the Commission should determine the size of this issue.

77. There are complexities in integrating demand response into the CAISO energy market – both technical and otherwise – that lead us to move forward in a more measured approach.

78. There is no record in this proceeding regarding the effectiveness of the DRAM.

79. We cannot determine at this time whether the DRAM is successful or whether it will become one of several procurement mechanisms or the sole mechanism.

80. We must determine if the DRAM pilot is feasible and whether it is successful.

81. We find questionable SCE's statement that restrictions in other demand response markets for the purpose of ensuring a level playing field for the DRAM pilot are unnecessary.

82. SCE stated that there are finite groups of demand response participants.

83. SCE expressed concern regarding a pattern of frequent migration by demand response customers from one demand response program to another.

84. The Commission cannot dismiss as unnecessary, ORA and TURN's request for a level playing field for the DRAM pilot, based on the number of available customers when that number is unknown.

85. No party provided evidence of restrictions in demand response programs leading to decreases in participation.

86. The Commission cannot discount ORA and TURN's request for a level playing field for the DRAM pilot, based on an unsupported alleged decrease in overall participation.

87. The Commission cannot solely rely on restrictions to demand response programs to ensure positive outcomes in either the DRAM pilot or current programs.

88. The Commission should ensure that the DRAM pilot has an opportunity to be tested.

89. The Commission has previously stated its desire to implement a competitive mechanism for bidding supply resources into the CAISO market.

90. It is not possible to measure the pilot's success or even feasibility when it has limitations on participation.

91. Using the DRAM to attack one demand response program is inappropriate.

92. Creating set-asides to avoid a crowding out effect is a reasonable way to ensure a level playing field for the DRAM pilot.

93. There is nothing in the record of this proceeding to determine a final set-aside to ensure a level playing field for the DRAM pilot.

Conclusions of Law

1. It is reasonable to adopt the terms and conditions set forth in Issue Area 1 of the Settlement, with our modifications.

2. It is reasonable to adopt the terms and conditions set forth in Issue Areas 2 and 4 of the Settlement, with our modifications.

3. It is reasonable to adopt the terms and conditions set forth in Issue Area 3, with our modifications.

4. It is reasonable to adopt the terms and conditions set forth in Issue Area 5, with our modifications.

5. The Settlement, as modified, is consistent with the law and past Commission decisions.

6. The Settlement, as modified, is in the public interest.

7. The Settlement, as modified, should be approved.

8. It is reasonable that demand response tariffs and programs available to all customers should be paid for by all customers.

9. It is reasonable to adopt requirements to address the barriers to the implementation of demand response programs by direct access and community choice aggregation providers.

10. Public Utilities Code Section 701 provides the Commission with broad authority.

11. Public Utilities Code Section 701.1 indicates the Legislatures intent that in addition to other ratepayer protection objectives, a principal goal of resource planning is to improve the environment.

12. It is reasonable for the Commission to direct the collection of data to determine the size of the use of backup generation by demand response customers.

13. It is not reasonable to adopt a preferred mechanism for bidding supply resources into the CAISO market when no mechanism has been tested for feasibility or success.

14. It is reasonable to provide the DRAM pilot a reasonably-sized market for test purposes thus ensuring a level playing field.

O R D E R

IT IS ORDERED that:

1. Pursuant to Commission Rules of Practice and Procedure 12.4(c), we grant the Motion for Adoption of Settlement Agreement, as modified in Ordering Paragraphs 3, 4, 5, and 6, between and among the following parties (in alphabetical order): Alliance for Retail Energy Markets, The California Independent System Operator, California Large Energy Consumers Association, Clean Coalition, Comverge, Inc., Consumer Federation of California, Direct Access Customer Coalition, EnergyHub/Alarm.com, EnerNOC, Inc., Environmental Defense Fund, Johnson Controls, Inc., Marin Clean Energy, Office of Ratepayer Advocates, Olivine, Inc., Pacific Gas and Electric Company, San Diego Gas & Electric Company, Sierra Club, Southern California Edison Company, and The Utility Reform Network.

2. Pursuant to Commission Rules of Practice and Procedure 12.4(c), Alliance for Retail Energy Markets, The California Independent System Operator, California Large Energy Consumers Association, Clean Coalition, Comverge, Inc., Consumer Federation of California, Direct Access Customer Coalition, EnergyHub/Alarm.com, EnerNOC, Inc., Environmental Defense Fund, Johnson Controls, Inc., Marin Clean Energy, Office of Ratepayer Advocates, Olivine, Inc., Pacific Gas and Electric Company, San Diego Gas & Electric Company, Sierra Club, Southern California Edison Company, and The Utility Reform Network have fifteen (15) days following the issuance of this decision to file, in this

proceeding, a compliance letter electing to either accept the modifications herein or request other relief.

3. We adopt the terms and conditions of Issue Area 1 of the Settlement, as attached in Appendix 1 of this decision, with the following modifications:

   a. Emergency and Reliability Demand Response Programs do not count toward the proposed interim five percent goal.

   b. The Demand Response Potential Study shall be designed by staff using the parameters of the Settlement as a guideline.

   c. The Commission will address the issue of program categorization, after the completion of the Demand Response Potential Study and the outcomes of the Working Groups.

   d. Commission staff is directed to begin the design phase immediately upon approval of this decision.

   e. Commission staff is directed to present the design to all stakeholders at an Administrative Law Judge facilitated workshop held within a reasonable time following the issuance of this decision.

   f. The Demand Response Potential Study will be completed no later than one calendar year from its commencement.

   g. Commission staff is directed to provide a final report to the assigned Administrative Law Judge on the Demand Response Potential Study no later than 90 days from the completion of the study.

4. We adopt the terms and conditions of Issue Areas 2 and 4 of the Settlement, as attached in Appendix 1 of this decision, with the following modifications:

   a. The 2017-2019 demand response program cycle will be full transitional program cycle beginning with small steps toward bifurcation in 2017 and ending with fully implemented bifurcation in 2019. Resource adequacy policy developed in Rulemaking 14-10-010 and its successor proceedings will flow through to demand response resources as it is developed.

b. The hiring of additional experts for the Valuation Working Group may be necessary but is capped at $200,000 over the life of the Valuation Working Group.

c. We deny, at this time, the contention that a demand response program can be partitioned into a load modifying and supply resource. Any such future contention, for example in a report, must be accompanied by supporting facts.

d. The process described in Section B.11.e of the Settlement, regarding the identification and resolution of how unmet goals can be met, shall be considered when the Commission considers the results of the Demand Response Potential Study.

e. During the identification of the values of supply and load modifying resources, the Load Modifying Resource Demand Response Valuation Group should capture the value provided by resources by demonstrating that neither load modifying nor supply resources receive an unfair advantage through favorable valuation.

f. We establish the following reporting requirements: a) Integration Working Group – Quarterly Reports (filed as compliance reports) on the meetings held, the products developed, and the groups' successes and missteps; the mid-year report referred to in the charter, which is to include proposed changes, priorities and time-line, shall also be filed no later than June 30, 2015, as a compliance report; b) Valuation Working Group -- the May 1, 2015 report referenced in the charter shall be filed as a compliance report; c) Operations Working Group – Quarterly Reports (filed as compliance reports) on the meetings held, the products developed, and the groups' successes and missteps. The Quarterly Reports will be due on April 1, July 1, October 1 and January 1 until the completion of this proceeding. The Quarterly Reports may be filed by one or more representatives of the Settling Parties, but the ultimate responsibility of ensuring the filing of these reports shall fall on PG&E, SDG&E, and SCE.

5. We adopt the terms and conditions of Issue Area 3 of the Settlement, as attached in Appendix 1 of this decision, with the following modifications:

a. In addition to the design, protocol and standard contracts for the Demand Response Auction Mechanism pilot, the pilot design working group shall also develop standard evaluation criteria.

b. In addition to the items in Ordering Paragraph 3.a, the pilot design working group shall also develop and recommend a proposal for a set-aside for the Demand Response Auction Mechanism pilot, based on location, customer class or attribute, or end uses.

c. The Demand Response Auction Mechanism pilot design, set-asides requirements, protocols, standard pro forma contracts, evaluation criteria and non-binding cost estimates will be filed at the Commission as a Tier Three advice letter, no later than April 1, 2015.

d. Fund shifting in the 2015-2016 demand response approved bridge funding budget will be allowed by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, the Utilities) for the sole purpose of funding the Demand Response Auction Mechanism pilot with the following caveats: 1) The Utilities shall not eliminate any other approved demand response program in order to fund the pilot without proper authorization from the Commission; and 2) The Utilities shall continue to submit a Tier Two Advice Letter before shifting more that 50 percent of any one program's funds to the pilot.

6. Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company are authorized to participate collaboratively with other interested stakeholders in the Demand Response Auction Mechanism pilot design working group. The activities of this working group shall be pursuant to the express direction and continuing supervision of the Commission through review and approval by the Commission of a final pilot design.

7. We adopt the terms and conditions of Issue Area 5 of the Settlement, as attached in Appendix 1 of this decision, with the following modifications:

a. A Ruling to be issued by the assigned Administrative Law Judge in this proceeding will be issued in May 2015 providing guidance on the 2017-2019 demand response budget and program applications to be filed by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company no later than November 30, 2015.

b. During the 2017-2019 Demand Response Transitional Program Cycle, two end-of- year workshops will be facilitated by the assigned Administrative Law Judge. Each workshop shall be held in early 2018 and again in early 2019.

c. The provision that the Commission approve the extended budget cycle no later than March 31, 2016 is denied.

8. We adopt the following cost causation principles for demand response:

a. Any demand response program or tariff that is available to all customers shall be paid for by all customers. If a demand response program or tariff is only available to bundled customers, the costs for that program or tariff can only be borne by bundled customers.

b. Once a direct access or community choice provider implements its own demand response program, the competing utility shall, no later than one year following the implementation of that program: i) end cost recovery from that provider's customers for any similar program and ii) cease providing the similar program to that provider's customers.

9. The assigned Administrative Law Judge will facilitate a workshop to determine how to implement the competitive neutrality cost causation principle adopted in Ordering Paragraph 8b.

10. The Commission confirms the following policy statement for demand response: Fossil-fueled backup generation is antithetical to the efforts of the Energy Action Plan and the Loading Order.

11. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall require any non-residential demand response contracted customer to self-certify the following:

    a. Whether the customer owns or operates a backup generator; and

    b. If the customer owns such a generator, what is the make, model and location of the generator.

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

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

14. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file a tier one advice letter, within 60 days from the issuance of this decision, revising its tariffs to implement the data collection required by Ordering Paragraphs 11, 12, and 13.

15. Phases Two, Three and Four of Rulemaking 13-09-011 remain open to complete the resolution of the scoping issues in those phases.

This order is effective today.

Dated _____________________________, at San Francisco, California.

APPENDIX 1

JOINT MOTION AND SETTLEMENT