

Decision 14-12-024 December 4, 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**

Table of Contents

Title	Page
DECISION RESOLVING SEVERAL PHASE TWO ISSUES AND ADDRESSING THE MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT ON PHASE THREE ISSUES.....	1
Summary	2
1. Background.....	3
2. Overview of Joint Motion and Settlement	9
2.1. Issue Area 1: Demand Response Goals.....	10
2.2. Combined Issue Area 2 and Issue Area 4: Valuation/Program Categorization and CAISO Integration	10
2.3. Issue Area 3: Demand Response Auction Mechanism, Utility Roles, and Future Procurement	12
2.4. Issue Area 5: Budget Cycle	13
3. Standard of Review of Settlements	13
4. Discussion and Analysis of the Proposed Settlement.....	14
4.1. The Proposed Settlement, with Modifications, is Reasonable in Light of the Record.....	15
4.1.1. Issue Area 1 is Reasonable with Modifications.....	16
4.1.2. Issue Areas 2 and 4 are Reasonable with Modifications.....	22
4.1.3. Issue Areas 3 is Reasonable with Modifications	32
4.1.4. Issue Areas 5 is Reasonable with Modifications	38
4.2. The Settlement, as Modified, is Consistent with Law and Prior Commission Decisions	40
4.3. The Settlement, as Modified, is in the Public Interest.....	42
5. Discussion and Analysis of Briefing on the Remaining Phase Two Issues and Phase Three Issue	43
5.1. Phase Two: Cost Allocation.....	43
5.1.1. Background: Cost Allocation	44
5.1.2. Discussion: Cost Allocation.....	47
5.2. Phase Two: Use of Backup Generation.....	50
5.2.1. Background: Use of Backup Generation	51
5.2.1. Discussion: Use of Back-Up Generation.....	52
5.3. Phase Three: Should the DRAM be the Preferred Means for Procuring Demand Response Supply Resources?	62
5.3.1. Overview: DRAM as the Preferred Procurement Mechanism and Encouraging DRAM Pilot Participation	63

Table of Contents (cont.)

Title	Page
5.3.1. Discussion: DRAM as the Preferred Procurement Mechanism and Encouraging DRAM Pilot Participation	65
6. Comments on Proposed Decision	70
7. Assignment of Proceeding	72
Findings of Fact	72
Conclusions of Law	81
ORDER	82

Appendix 1 - Joint Motion and Settlement

**DECISION RESOLVING SEVERAL PHASE TWO ISSUES AND ADDRESSING
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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 Order Instituting Rulemaking (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

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

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 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 existing 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

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.

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 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

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

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 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 Parties⁵ 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

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).

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.

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.

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 back-up generators. The issues of cost allocation and back-up 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

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

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.”

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 beyond 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 unsatisfied with 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 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.

⁹ Public Utilities Code Section 1701.5 requires the Commission to resolve the issues raised in the scoping memo by the 18-month deadline.

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 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

¹⁰ Settlement at 6.

¹¹ Settlement at 6-7.

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 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

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.

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 (DR) 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 programs¹⁹ 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 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

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.

²⁰ Settling Parties Comments to Alternate Proposed Decision at 6.

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.

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

²¹ *Id.* at 7.

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

As the 5 percent goal is considered interim, parties should not rely on this number for definitive planning activities. Rather it should serve as a soft guidepost for where the policy may be at the resolution of the study on demand response potential and resulting goals. We further note that as a metric percent of peak demand captures well the Commission's intent to continue supporting DR, but it does not effectively represent a range of other objectives the Commission has for DR. For example, DR successfully integrated into CAISO's ancillary services market provides operational benefits that are not captured by the comparatively simple percent of peak load metric. Further examples include, but are not limited to the dispatchability, dependability, and cost-effectiveness of

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.

DR. We therefore acknowledge and give notice that as a part of our refining of DR goals in the coming years, additional metrics will be identified and adopted.

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 compromise the April 2014 Scoping Memo categories of resource adequacy concerns, supply and load modifying resource issues, and CAISO market integration costs.

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.
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 existing 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.

TABLE 2	
SCOPING MEMO ISSUES ADDRESSED IN ISSUE AREAS 2 & 4	
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.
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

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.

recommendations to resolve them. The Settlement provides a process for exactly 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 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

²⁶ Calpine Comments at 5.

²⁷ Settlement at Attachment B, page 3, section 12.

²⁸ Calpine Comments at 5.

²⁹ Response to Calpine Comments at 8, footnote 33, citing the Settlement at 6.

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 2018, following a 2016-2017 transitional period. We reject the component of the settlement that freezes the current resource adequacy rules for load modifying demand response for any period of time. 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 alternate proposed decision, the Settling Parties urged the Commission to confirm that full implementation of bifurcation includes 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 additional fourth item of the adoption of the categorization of demand response programs into load modifying and supply side products. We reiterate and emphasize, however, that adoption of resource adequacy treatment will take place in the resource adequacy proceeding, and the current valuation used to calculate the system and local resource adequacy credits for all existing programs will not be frozen in this proceeding until any period of time. Furthermore, once

³⁰ *Id.* at 7.

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

that adoption occurs, the rules will automatically and immediately to this proceeding.

We envision the path to 2018 will include the following steps:

1. Commission decision authorizing bridge funding for 2017³² for the existing utility programs, including their contracts with third-party demand response providers or aggregators (also known as the AMP program). As described below, the 2016 and 2017 years are viewed as transitional years meaning that we hope to incrementally change DR programs in those years so that the transition to full bifurcation in 2018 is smooth and with as little disruption as possible.
2. Commission decision that adopts DR goals for 2018 and beyond. This decision will be informed by a DR Potential Study. This decision could also serve as an all-purpose 'guidance' decision for any other policy guidance that is not covered by the milestones below.
3. Commission decision that adopts changes to the DR Cost-Effectiveness Protocol. The protocol has been a primary tool of the Commission in determining if a DR program should receive ratepayer funding.
4. Commission decision in the Resource Adequacy proceeding. This decision will likely set new RA requirements for DR resources (both Supply-Side and Load-Modifying).
5. CAISO implementation of new rules or operations (if any). The CAISO is considering various changes to its rules, operations and policies in the Supply Side Integration Working Group and the Load-Modifying (L-M) Operations Working Group. To the extent that CAISO makes changes to existing operations/rules, it would be ideal if those changes happen by mid-2016.

³² TR, Vol. 3 at 186-187.

6. Results from the 2016 DRAM pilot. These results should be included in the IOUs' DR applications so that the Commission can determine if/when expansion of the DRAM should happen.
7. In November 2016, PG&E, SDG&E, and SCE are directed to submit applications for the 2018 and post 2018 demand response portfolios. The guidance for the 2018 and beyond portfolio will be developed from the above items in this list.³³

Furthermore, we find that many issues in the April 2014 Scoping Memo are not resolved. The Settlement proposes a process by which remaining issues may be resolved. 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 may add this task to the design of the Study.

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

- First, and foremost, as discussed above, we reject the Settlement's proposal that we retain current system and local RA valuation based on existing methodology through 2019. While we acknowledge the desire by the Settling Parties to take a

³³ TR, Vol. 3 at 186-187.

“measured approach” to the transition to bifurcation but believe we can and must move more quickly. Therefore we modify the Settlement to designate the 2016 and 2017 demand response funding periods as a transition period. The period begins with small steps toward bifurcation in 2016 and ends with fully implemented bifurcation in 2018. Resource adequacy credits will flow through to demand response programs once adopted by the Commission in the Resource adequacy proceeding. Section 4.1.4 provides an overview of a process for incremental changes to be considered and implemented. Thereby beginning January 1, 2018, the transition period will be over and all demand response programs will need to meet resource adequacy rules to either reduce the resource adequacy requirement as a load-modifying resource or to count toward meeting the resource adequacy requirement as a supply resource.

- 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 Working Group’s effort. 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.³⁴ 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 – 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 necessity to vet and integrate the results, all finalized Valuation Working Group conclusions must be filed to the Commission in a compliance report by May 1, 2015;
 - c) Operations Working Group – Given the narrow scope of the working group and the necessity to vet and integrate the results, all finalized Valuation Working Group conclusions must be filed to the Commission in a compliance report by June 30, 2015; and

³⁴ TR, Vol. 3 at 186-187.

- o d) Any required submissions 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. If the Working Groups fail to comply with any stated deadlines, Energy Division shall develop a proposal to be included in future DR planning proceedings.

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.

TABLE 3	
SCOPING MEMO ISSUES ADDRESSED IN ISSUE AREA 3	
SCOPING MEMO ISSUE	MEANS BY WHICH ADDRESSED
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.”³⁵ 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.”³⁶ 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.³⁷ In response, the Settling Parties disagree with Calpine’s statements regarding a reduction in the role of the DRAM. The Settling

³⁵ Settlement at 15.

³⁶ Calpine Comments at 7.

³⁷ *Ibid.*

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.³⁸

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.³⁹ Furthermore, ORA expressed concern regarding sufficient participation for a successful auction, if the auction 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.⁴⁰

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.⁴¹ 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.⁴² The Settling Parties contend that the integration issues are

³⁸ Response at 5-6.

³⁹ June Workshop Report at Section II.G.4.

⁴⁰ OIR at 18.

⁴¹ Settlement at 9.

⁴² Motion for Adoption of Settlement at 15.

central to the development of a fully implemented DRAM.⁴³ A DRAM pilot would allow the details of the auction mechanism to be refined with experience⁴⁴ 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.⁴⁵ A pilot is a cost-effective 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.”⁴⁶ As the Commission stated in D.14-03-026, bidding demand response into the CAISO market is a complex process.”⁴⁷ 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

⁴³ Settlement at 9.

⁴⁴ Settlement at 10.

⁴⁵ See, for example, the pilots approved in concept in D.12-04-045 at 176.

⁴⁶ June Workshop Report at II.C.2

⁴⁷ D.14-03-026 at Finding of Fact 17.

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. 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.”⁴⁸ 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.⁴⁹ 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.

⁴⁸ OIR at 16.

⁴⁹ D.12-04-045 at 190.

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;⁵⁰
- b. The DRAM pilot design, 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; 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 than 50 percent of any one program's funds to the pilot.⁵¹

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

⁵⁰ Settlement at 25.

⁵¹ D.12-04-045 at Ordering Paragraph 4.

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. Phoebe 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.⁵² It is our intention that the authority we 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.

⁵² D.10-06-009 at 8-9.

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.⁵³ 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 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.⁵⁴ 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

⁵³ Settlement at 11.

⁵⁴ *Id.* at 11 and 30.

bring new programs online based on innovations, ensuring that portfolios are cost-effective and based on the best-available data.⁵⁵ The Settling Parties lay out a course for reviewing and making determinations on future budget cycles through a collaborative effort that addresses these issues.⁵⁶ 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. A Ruling by the assigned Administrative Law Judge in this proceeding will be issued in 2015 will initiate the process to authorize a 2017 bridge funding period.
- b. Because we consider years 2016 and 2017 to be transitional, we require two end-of-year review workshops, facilitated by the assigned Administrative Law Judge. The workshops, to be held in late 2015 and again in late 2016, should ensure that each successive year of the transitional cycle moves the Commission closer to full CAISO market integration and full bifurcation implementation. Advice letters will be used to the extent that any transitions require tariff or contract changes are necessary; 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

⁵⁵ OIR at 16.

⁵⁶ See, for example, Settlement at 11 regarding uncertainty, Settlement at 30 requiring cost-effectiveness, and Settlement at 31 requiring the frequency of reviews.

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.⁵⁷ 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 supply resource.⁵⁸ 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."⁵⁹

The Commission has already determined that complete implementation of bifurcation cannot occur until resource adequacy issues have been resolved.⁶⁰

⁵⁷ D.14-03-026 at Ordering Paragraph 1.

⁵⁸ Settlement at 8.

⁵⁹ *Ibid.*

⁶⁰ D.14-03-026 at 12 and at Finding of Fact 14.

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.⁶¹ Thus, we conclude that the Settlement, as modified, is consistent with the law and past Commission decisions.

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.⁶² 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

⁶¹ D.14-03-026 at 10-11.

⁶² See D.11-12-053 at 76, discussing settlements.

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.⁶³

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 back-up 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 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.

⁶³ OIR at 3.

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.⁶⁴ 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.⁶⁵ 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;

⁶⁴ DACC/AReM Opening Brief at 2.

⁶⁵ DACC/AReM Opening Brief at 6-7.

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.”⁶⁶ 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 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.⁶⁷

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

⁶⁶ Marin Clean Energy Opening Brief at 9.

⁶⁷ Shell Energy Opening Brief at 10.

CLECA, PG&E, SDG&E, SCE, and TURN all contend that the current policies regarding cost allocation are equitable and should not be changed.⁶⁸ 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.⁶⁹ 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 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.⁷⁰ 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.⁷¹ CLECA contends that the Commission should not

⁶⁸ 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.

⁶⁹ PG&E Opening Brief at 19.

⁷⁰ SCE Opening Brief at 4-5.

⁷¹ SDG&E/TURN Opening Brief at 2.

set allocation based on bifurcation categories because a supply resource provides more benefits than reducing generation needs.⁷²

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.12-04-045.⁷³

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 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.⁷⁴

⁷² CLECA Opening Brief at 13-16.

⁷³ DACC/AReM Opening Brief at 4-5, citing D.12-04-045 at 204.

⁷⁴ DACC/AReM Reply Brief at 6.

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.⁷⁵ 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.⁷⁶ 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 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

⁷⁵ R.12-06-013.

⁷⁶ DACC/AReM Opening Brief at 5.

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.⁷⁷ 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

⁷⁷ Supporting Parties Reply Brief at 5.

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 back-up 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 with regard to greenhouse gas amelioration.⁷⁸ 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 back-up generators being used and the extent to which they are being used. Therefore, as further described below, we direct the

⁷⁸ 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.)

utilities to collect information regarding the use of back-up generators 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

Conclusion of law 5 of D.11-10-003 states that “[i]t is reasonable to adopt as a policy statement that fossil-fuel emergency back-up generation resources should not be allowed as part of a demand response program for RA purposes, subject to rules adopted in future RA proceedings.” 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 back-up 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 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 back-up generation.⁷⁹

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 back-up 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

⁷⁹ D.11-10-003, Ordering Paragraph 3 at 34.

determination, D.12-04-045 deferred all issues related to back-up generation to R.07-01-041 or its successor proceeding.

The OIR for R.13-09-011 inadvertently omitted the issue of back-up generation. However, the issue of back-up generation was discussed at the pre-hearing conference⁸⁰ 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 back-up generation generally fall into two categories: a) regulating the use of back-up generation is not in the jurisdiction of the Commission, but rather the California Air Resources Board and local air quality management districts;⁸¹ or b) the Commission has already concluded that it “should” prohibit back-up generation for demand response.⁸²

5.2.1. Discussion: Use of Back-Up Generation

There are four questions before us regarding the use of back-up generation: 1) What is the Commission’s current policy regarding the use of back-up generation in demand response programs; 2) Whether the Commission has the jurisdiction to determine whether demand response programs should

⁸⁰ Prehearing Conference Transcript at 55.

⁸¹ 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.)

⁸² 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 back-up generators and ORA recommends that the use of backup generation should be strictly prohibited and penalized.

allow the use of back-up generation; 3) If the Commission has jurisdiction, whether it should allow the use of back-up 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 back-up 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.

TABLE 5 Historical Policy Regarding the Use of Backup Generation in Demand Response ⁸³	
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.” ⁸⁴
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.

⁸³ Sierra Club and NRDC Opening Brief at 6-8.

⁸⁴ D.03-06-032, Attachment A at 2.

<p>TABLE 5</p> <p>Historical Policy Regarding the Use of Backup Generation in Demand Response⁸³</p>	
<p>D.05-01-056 Approving the 2005 Demand Response Programs and Budgets.</p>	<p>In denying PG&E’s requested back-up 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.”</p>
<p>D.06-11-049.</p>	<p>In denying PG&E’s request to fund a retrofit of exiting customer-owned diesel back-up 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 Back-Up Generation program.”⁸⁵</p>
<p>Energy Action Plan (2008).</p>	<p>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.⁸⁶</p>
<p>D.09-08-027.</p>	<p>In rejecting a proposal by Blue Point Energy to recognize back-up generation as demand response, the Commission stated that “as a policy matter, we have already found that subsidizing back-up generation with demand response funds is not appropriate; we prefer to reserve these funds for activities that reduce total energy use.”⁸⁷</p>

⁸⁵ D.06-11-049 at 58.

⁸⁶ State of California, Energy Action Plan, 2008 Update, February 2008.

⁸⁷ D.09-08-027 at 164-166.

TABLE 5 Historical Policy Regarding the Use of Backup Generation in Demand Response ⁸³	
D.11-03-003.	The Commission stated that, “we do not want to allow fossil-fueled emergency back-up 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 back-up generation were contradictory to our vision for demand response and the Loading Order.” ⁸⁸

The Joint Demand Response Parties contend that ORA, the Sierra Club and NRDC and documents in this rulemaking have misstated the adopted policy on back-up 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.⁸⁹ 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.⁹⁰ 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.⁹¹ We disagree. The Commission has

⁸⁸ D.11-10-003 at 26.

⁸⁹ Joint Demand Response Parties Opening Brief at 9.

⁹⁰ See, e.g., *City of San Jose v. Superior Court*, 5 Cal. 4th 47, 55 (1993).

⁹¹ *Id.* at 10.

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 back-up generation should be permitted in demand response programs. CLECA argues that federal, state and local air quality agencies have clear jurisdiction over back-up generation and the Commission does not.⁹² 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 automobiles.”⁹³ Both CLECA and SCE surmise that the Commission should recognize and defer the regulation of back-up generation to those agencies entrusted with air quality.⁹⁴ 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.⁹⁵ The Joint Demand Response Parties assert that the jurisdictional role

⁹² CLECA Opening Brief at 7, citing SCE-02 at 17.

⁹³ SCE Opening Brief at 7-8.

⁹⁴ CLECA Opening Brief at 7 and SCE Opening Brief at 8.

⁹⁵ 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.

and impact of air quality regulations on the use of back-up generation cannot be ignored.⁹⁶

In reviewing the Commission's past statements regarding the use of back-up 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 back-up generation have addressed an aversion to the use of technologies, such as fossil-fueled back-up 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 Commission to effectively regulate the use of back-up generation by all demand response participants.⁹⁷ 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.⁹⁸ 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,

⁹⁶ Joint Demand Response Parties Opening Brief at 17.

⁹⁷ Supporting Parties Reply Brief at 4.

⁹⁸ *Ibid.*

we conclude that the Commission has the authority to regulate the use of back-up 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 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,⁹⁹ the EPA made clear that it did not intend to preempt more stringent state requirements:

[T]he 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 back-up generation by Commission-regulated demand response programs, several parties assert that it is premature and/or there is not sufficient evidence in the record.¹⁰⁰ CLECA and PG&E add that the Utilities should not be required to collect information on the use of back-up 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.¹⁰¹ CLECA asserts that the Commission

⁹⁹ The document appears here:

<http://www.epa.gov/ttn/atw/icengines/docs/20140801responsetocomments.pdf>
(Response to Comments).

¹⁰⁰ 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.

¹⁰¹ PG&E Opening Brief at 25.

should not increase the reporting burden on customers beyond what is required by air quality regulators.¹⁰²

We agree that there is insufficient evidence in the record to determine whether it is prudent to prohibit back-up 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 back-up generation and identify the amount of demand response provided by back-up generators.¹⁰³ This has not been completed.¹⁰⁴ In D.11-10-003, the Utilities were directed to work with Commission Staff to identify data on how customers intend to use back-up generation and identify the amount of demand response provided by back-up generation when enrolling new customers in, or renewing, demand response programs.¹⁰⁵

In reply briefs, the Supporting Parties note that there is not a clear picture of how prevalent the use of back-up generation is by demand response participants.¹⁰⁶ Before we determine whether it is prudent to regulate the use of back-up 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 back-up generator and, if they do,

¹⁰² CLECA Opening Brief at 9.

¹⁰³ SCE Opening Brief at 10 and Joint Demand Response Parties Opening Brief at 9 and 10.

¹⁰⁴ Joint Demand Response Parties Opening Brief at 12.

¹⁰⁵ D.11-10-003 at Ordering Paragraph 3.

¹⁰⁶ Supporting Parties Reply Brief at 4.

provide the make, model and location of the generator.¹⁰⁷ 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 back-up generators owned by customers that participate in their programs. In comments to the alternate proposed decision, SCE argued that some owners of BUGs don't have hourly data because of the nonexistence 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.

In comments to the alternate 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.

¹⁰⁷ See NRDC/Sierra Club Opening Brief at 6.

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.¹⁰⁸ 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.¹⁰⁹ ORA concludes that these limitations should lead the Commission to support the 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.”¹¹⁰

In opposition to ORA, several parties (CLECA, Joint Demand Response Parties, PG&E, SDG&E and SCE) consider it premature to designate the DRAM

¹⁰⁸ ORA Opening Brief at 5.

¹⁰⁹ ORA Opening Brief at 7.

¹¹⁰ TURN Opening Brief at 7.

as the preferred method of procurement. Similar to TURN, CLECA contends that this issue should be determined by the experience of the pilot.¹¹¹ 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.¹¹² 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.¹¹³

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 encouraging participation in the DRAM pilot. SCE cautions that such limitations could jeopardize current programs by reducing overall participation.¹¹⁴ Joint Demand Response Parties contend that there is no record to support restrictions on demand response programs for the purpose of encouraging participation.¹¹⁵

¹¹¹ CLECA Opening Brief at 17.

¹¹² SCE Opening Brief at 12-13.

¹¹³ PG&E Opening Brief at 29-30.

¹¹⁴ SCE Opening Brief at 12 and 16.

¹¹⁵ Joint Demand Response Parties Opening Brief at 24.

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.¹¹⁶

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 be procured by other means such as the utilities' requests for offers with much more attractive terms than a competitive auction.¹¹⁷ TURN recommends that the Commission establish set asides for the two auctions defined by location, customer class or attribute, or end uses.¹¹⁸ 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.¹¹⁹

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,

¹¹⁶ PG&E Opening Brief at 31.

¹¹⁷ TURN Opening Brief at 8.

¹¹⁸ TURN Opening Brief at 9.

¹¹⁹ ORA Opening Brief at 7 and 10.

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.¹²⁰ 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.¹²¹ 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.¹²²

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

¹²⁰ ORA Reply Brief at 5.

¹²¹ Joint Demand Response Parties Opening Brief at 25 quoting form D.14-03-026 at 27.

¹²² 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.”

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.¹²³ 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.¹²⁴ Both ORA and TURN recommend that the Commission adopt provisions to provide a level playing field for the DRAM pilot.

First, SCE states that these restrictions are unnecessary given that there is still untapped demand response potential that the DRAM pilot could explore.¹²⁵ We question this statement given that SCE previously stated that there are finite groups of demand response participants.¹²⁶ Additionally, SCE expressed concern

¹²³ ORA Opening Brief at 9.

¹²⁴ TURN Opening Brief at 8.

¹²⁵ SCE Opening Brief at 12.

¹²⁶ June Workshop Report at II.F.1.a and II.F.3.

regarding a pattern of frequent migration by customers from one demand response alternative to another.¹²⁷ 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.¹²⁸ Joint Demand Response Parties contend that if the DRAM pilot is well designed and structured, it should encourage customer participation.¹²⁹ PG&E agrees, and suggests that the design of the DRAM pilot could include a direct mechanism to encourage participation.¹³⁰ PG&E further suggests that the DRAM pilot could use a prior PG&E pilot as an example of a significant outreach

¹²⁷ June Workshop Report at II.F.1.a.

¹²⁸ Joint Demand Response Parties Opening Brief at 24.

¹²⁹ Joint Demand Response Parties Opening Brief at 25.

¹³⁰ PG&E Opening Brief at 31.

and recruitment effort.¹³¹ ORA disputes this recommendation, noting that the findings of the pilot in question, the IRM2,¹³² concluded that non-investor owned utility load shedding entities have been reluctant to support their customers' participation in the IRM2.¹³³ 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."¹³⁴ The Commission has previously stated its desire to implement a competitive mechanism for bidding supply resources into the CAISO market.¹³⁵ 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

¹³¹ PG&E Opening Brief at 31.

¹³² 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.

¹³³ ORA Reply Brief at 3.

¹³⁴ TURN Opening Brief at 8.

¹³⁵ Revised Scoping Memo at 5.

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.¹³⁶ 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,¹³⁷ the set-asides should not be construed as setting precedent in the final procurement mechanism adopted by the Commission.

6. Comments on Alternate Proposed Decision

The Proposed and Alternate Proposed Decisions of the Administrative Law Judge and Commissioner Peevey 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.

¹³⁶ Supporting Parties Reply Brief at 10.

¹³⁷ Settlement at 24: This DRAM Pilot will not set precedent for future procurement of Supply Resources.

The Judge permitted parties to separately file comments on the Settlement and the litigated issues.¹³⁸ 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, 2014 by DACC/AReM, Joint Demand Response Parties, Marin Clean Energy, ORA, PG&E, and SCE. In response to comments to the Alternate Proposed Decisions, 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.¹³⁹ The Settling Parties contend that an early start to this working group, prior to a final decision on the approval of the Settlement, is necessary to timely commence the DRAM pilot.¹⁴⁰ 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.¹⁴¹ In comments to the Alternate

¹³⁸ Administrative Law Judge Ruling issued on November 6, 2014. See also Ruling issued on November 19, 2014 increasing page limit.

¹³⁹ Motion at 3.

¹⁴⁰ Motion at 20.

¹⁴¹ TR, Vol. 3, at 163, lines 19-24. See also TR, Vol. 3 at 173-174.

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 Alternate 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.
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. Issue Area 1 of the Settlement does not set a specific future goal for demand response.
6. Issue Area 1 of the Settlement sets forth a process to lead the Commission to a determination of specific future goals for demand response.
7. 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.
8. The Settlement provides no justification as to why emergency or reliability demand response programs should now be included as part of the interim goal.
9. Categorization of demand response programs is not adequately addressed in Issue Area 2 of the Settlement.
10. In D.14-03-026, the Commission determined that bifurcation of the demand response programs would begin in 2017.
11. 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.
12. Bidding demand response into the CAISO market has been an objective of the Commission since 2007.
13. Bidding demand response into the CAISO market is a complex process based on multiple factors.
14. Calpine's concern regarding maintaining the current counting method through 2019 is valid.
15. 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.

16. 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.

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

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

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

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

21. 2020 is not a reasonable timeline for full implementation of bifurcation.

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

23. 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.

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

25. The 2016-2017 demand response program cycle will be a transitional cycle.

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

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

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

29. 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.

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

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

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

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

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

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

36. 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.

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

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

39. 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.

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

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

42. 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.

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

44. 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.

45. R.13-09-011 will still be active when the Utilities are preparing their applications for the 2018 demand response portfolios.

46. 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.

47. The Settling Parties have complied with the provisions of Rule 12 regarding Settlements.

48. 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.

49. The Utilities will submit 2018 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.

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

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

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

53. 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.

54. 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.

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

56. 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.

57. 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.

58. 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.

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

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

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

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

63. D.11-10-003 did not include in an ordering paragraph, and therefore, did not implement a prohibition of the use of fossil-fueled back-up generation in demand response programs.

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

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

66. The Commission has not attempted to regulate emissions.

67. 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.

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

69. There is insufficient evidence in the record of this proceeding to determine whether it is prudent for the Commission to prohibit the use of back-up generation in demand response programs.

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

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

72. Prior to determining whether it is prudent to prohibit the use of back-up generation in demand response, the Commission should determine the size of this issue.

73. 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.

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

75. 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.

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

77. 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.

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

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

80. 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.

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

82. 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.

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

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

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

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

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

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

89. 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 and use of back-up 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 the Commission's 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 the Commission's 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, Converge, 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. First, and foremost, we acknowledge the desire by the Settling Parties to take a “measured approach” to the transition to bifurcation but believe we can and must move more quickly. Therefore we modify the Settlement to designate the 2016 and 2017 demand response funding periods as a transition period. The period begins with small steps toward bifurcation in 2016 and ends with fully implemented bifurcation in 2018 to include the new valuations for resource adequacy credits. Thereby beginning January 1, 2018, the transition period will be over and all demand response programs will need to meet resource adequacy rules to either reduce the resource adequacy requirement as a load-modifying resource or to count toward meeting the resource adequacy requirement as a supply resource. 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 supply resources by demonstrating that neither load modifying nor supply resources receive an unfair advantage through favorable valuation.
- f. We establish the following reporting requirements:
 - i) Integration Working Group – Reports (filed as compliance reports) on the meetings held, the products developed, and the groups’ successes and missteps; the mid-year report referred to in the charter, which is to include proposed changes, priorities and time-line, shall also be filed no later than June 30, 2015, as a compliance report;
 - ii) Valuation Working Group – Given the necessity to vet and integrate the results, all finalized Valuation Working Group conclusions must be filed to the Commission in a compliance report by May 1, 2015;
 - iii) Operations Working Group – Given the narrow scope of the working group and the necessity to vet and integrate the results, all finalized Valuation Working Group conclusions must be filed to the Commission in a compliance report by June 30, 2015; and
 - iv) Any required submissions 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. If the Working Groups fail to comply with any stated deadlines, Energy Division shall develop a proposal to be included in future DR planning proceedings.
- g. In November 2016, PG&E, SDG&E, and SCE are directed to submit applications for the 2018 and post 2018 demand response portfolios.

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 than 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 by the assigned Administrative Law Judge in this proceeding will be issued in 2015 will initiate the process to authorize a 2017 bridge funding period.
 - b. Because we consider years 2016 and 2017 to be transitional, we require two end-of-year review workshops, facilitated by the assigned Administrative Law Judge. The workshops, to be held in late 2015 and again in late 2016, should ensure that each successive year of the transitional cycle moves the Commission closer to full CAISO market integration and full bifurcation implementation. Advice letters will be used to the extent that any transitions require tariff or contract changes are necessary.
 - 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 back-up generation is antithetical to the efforts of the Energy Action Plan and the Loading Order.

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

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

- a. Whether the customer owns or operates a back-up generator; and
- b. If the customer owns such a generator, what is the make, model and location of the generator.

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

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

15. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file a Tier One advice letter, within

60 days from the issuance of this decision, revising its tariffs to implement the data collection required by Ordering Paragraphs 11, 12, 13 and 14.

16. The assigned Commissioner and assigned Administrative Law Judge are authorized to take all procedural steps, including modifications to the schedule set forth herein, to promote the objectives in this decision and to provide clarification and direction as required to assure the effective, fair and efficient implementation of this decision in this proceeding or in successive demand response proceedings.

17. 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 December 4, 2014, at San Francisco, California.

MICHAEL R. PEEVEY
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
MICHAEL PICKER
Commissioners

APPENDIX 1

JOINT MOTION AND SETTLEMENT



FILED
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**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.

R.13-09-011
(Filed September, 2013)

**MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT BETWEEN AND
AMONG PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA
EDISON COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, CALIFORNIA
INDEPENDENT SYSTEM OPERATOR CORPORATION, OFFICE OF RATEPAYER
ADVOCATES, THE UTILITY REFORM NETWORK, CALIFORNIA LARGE
ENERGY CONSUMERS ASSOCIATION, CONSUMER FEDERATION OF
CALIFORNIA, ALLIANCE FOR RETAIL ENERGY MARKETS, DIRECT ACCESS
CUSTOMER COALITION, MARIN CLEAN ENERGY, ENERNOC, INC.,
COMVERGE, INC., JOHNSON CONTROLS, INC., OLIVINE, INC.,
ENERGYHUB/ALARM.COM, SIERRA CLUB, ENVIRONMENTAL DEFENSE FUND,
AND CLEAN COALITION ON PHASE 3 ISSUES**

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TABLE OF CONTENTS

	Page(s)
I. SUMMARY OF REQUESTED RELIEF	2
II. FACTUAL AND PROCEDURAL BACKGROUND OF PHASES TWO AND THREE.....	3
III. SETTLEMENT HISTORY AND RULE 12 COMPLIANCE	8
IV. CONTEXT, SCOPE, AND SUMMARY OF SETTLEMENT AGREEMENT.....	9
A. Settlement Context.....	9
B. Settlement Scope (“Issue Areas”).....	11
1. The Settlement Agreement Does Not Address or Resolve the Remaining Phase Two Issues.....	11
2. The Settlement Agreement Addresses All Phase Three Issues by “Issue Area.”	12
C. Summary of Settlement Agreement.....	13
1. Overview.....	13
2. By “Issue Area”	13
a. Issue Area #1: Demand Response Goals	13
b. Issue Area #2: Valuation/Program Categorization, and Issue Area #4: CAISO Integration.....	14
c. Issue Area #3: Demand Response Auction Mechanism (DRAM), Utility Roles, Future Procurement.	15
d. Issue Area #5: Budget Cycle.....	16
V. THE SETTLEMENT AGREEMENT IS REASONABLE, CONSISTENT WITH THE LAW, IN THE PUBLIC INTEREST, AND SHOULD BE ADOPTED BY THE COMMISSION.	17
VI. RULE 12.3 HEARINGS ARE NOT REQUIRED	19
VII. ADDITIONAL REQUESTED RELIEF IN FURTHERANCE OF THE SETTLEMENT AGREEMENT	19
VIII. CONCLUSION.....	21
ATTACHMENT A: SETTLEMENT AGREEMENT	
ATTACHMENT B: COMPARISON EXHIBIT	

TABLE OF AUTHORITIES

Page(s)

CALIFORNIA PUBLIC UTILITIES COMMISSION DECISIONS

D.88-12-183, *Re Pacific Gas & Electric Company* (Dec. 19, 1988; as amended June 16, 1989)
30 CPUC 2d 189 20

D.09-10-017, *Decision Adopting All-Party Settlement Agreement* (Oct. 16, 2009)..... 19

D.11-12-053, *Decision Adopting Electric Marginal Costs, Revenue Allocation And Non-Residential Rate Design For PG&E* (Dec. 22, 2011) 19, 20

D.12-04-045, *Decision Adopting Demand Response Activities And Budgets For 2012 Through 2014* (Apr. 30, 2012) 17, 18, 24

D.14-01-004, *Decision Approving Two-Year Bridge Funding For Demand Response Programs* (Jan. 24, 2014)..... 18

D.14-03-026, *Decision Addressing Foundational Issue Of The Bifurcation Of Demand Response Programs* (Apr. 4, 2014) passim

D.14-05-025, *Decision Approving Demand Response Program Improvements And 2015-2016 Bridge Funding Budget* (May 19, 2014) 18, 24

Rulings

Joint Assigned Commissioner And ALJ Ruling And Revised Scoping Memo (Apr. 2, 2014)..... 1

ALJ Ruling Requesting Comment On Proposed Revisions To The Cost-Effectiveness Protocols (June 23, 2014)..... 5, 13

ALJ's E-Mail Ruling Revising Schedule (July 31, 2014)..... 8, 24

CPUC RULES OF PRACTICE AND PROCEDURE AND GENERAL ORDERS

Rule 12.1(a)..... 1, 2, 10

Rule 12.1(b) 10

Rule 12.1(c)..... 3

Rule 12.1(d) 19

Rule 12.3 2, 22

Rule 12.5 10

Rule 12.6..... 9

**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.

R.13-09-011
(Filed September, 2013)

MOTION FOR ADOPTION OF SETTLEMENT AGREEMENT BETWEEN AND AMONG PACIFIC GAS AND ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION, OFFICE OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, CONSUMER FEDERATION OF CALIFORNIA, ALLIANCE FOR RETAIL ENERGY MARKETS, DIRECT ACCESS CUSTOMER COALITION, MARIN CLEAN ENERGY, ENERNOC, INC., COMVERGE, INC., JOHNSON CONTROLS, INC., OLIVINE, INC., ENERGYHUB/ ALARM.COM, SIERRA CLUB, ENVIRONMENTAL DEFENSE FUND, AND CLEAN COALITION ON PHASE THREE ISSUES

Pursuant to Rule 12.1(a) of the Commission's Rules of Practice and Procedure, the Joint Settling Parties^{1/} respectfully move for the adoption by the Commission of the attached Settlement Agreement (Attachment A hereto) on the issues included within the scope of Phase Three of this rulemaking. By the Settlement Agreement, the Settling Parties agree on a mutually acceptable outcome on the Phase Three issues identified in the "Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings" issued in this rulemaking on April 2, 2014 ("April 2 ACR").

1/ The Settling Parties include Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); San Diego Gas and Electric Company (SDG&E); California Independent System Operator Corporation (CAISO); Office of Ratepayer Advocates (ORA); The Utility Reform Network (TURN); California Large Energy Consumers Association (CLECA); Consumer Federation of California (CFC); Alliance for Retail Energy Markets (AReM); Direct Access Customer Coalition (DACC); Marin Clean Energy (MCE); EnerNOC, Inc. (EnerNOC); Comverge, Inc. (Comverge); Johnson Controls, Inc. (JCI); Olivine, Inc.; EnergyHub /Alarm.Com; Sierra Club; Environmental Defense Fund (EDF); and Clean Coalition (collectively, Settling Parties).

Rule 12.1(a) requires a motion proposing a settlement on the resolution of issues within the scope of a proceeding to “contain a statement of the factual and legal considerations adequate to advise the Commission of the scope of the settlement and of the grounds on which adoption is urged.” In compliance with that rule, this Motion provides (1) the factual and procedural background and scope of Phase Three of R.13-09-011, (2) the history of the Settlement Agreement and Rule 12 compliance, (3) a description of the context and scope of the Settlement Agreement, along with a summary of the Settlement Agreement, and (4) a demonstration that the Settlement Agreement is reasonable in light of the whole record, consistent with the law, and in the public interest; and (5) an exhibit that compares the Settling Parties’ testimony with the outcomes of the Settlement Agreement. No hearing, as described in Rule 12.3, is required. In addition, the Motion seeks additional relief consistent with the terms of the Settlement Agreement.

I. SUMMARY OF REQUESTED RELIEF

Based on the information contained herein and the Settlement Agreement attached hereto as Attachment A, the Settling Parties move for adoption of the Settlement Agreement by the Commission. It is the Settling Parties’ position that the settlement process and the Settlement Agreement fully comply with Rule 12 and that the Settlement Agreement, for the reasons stated herein, is reasonable in light of the whole record, consistent with the law, in the public interest, and should be adopted by the Commission.

Based on “time urgency,” as detailed below, the Settling Parties also request the following procedural rulings to facilitate timely consideration of the Settlement Agreement within the schedule adopted for Phases Two and Three.^{2/} These rulings are required to permit appropriate deviation from the Commission’s deadlines otherwise applicable to settlement agreements and to reflect resource constraints that have arisen in reaching the Settlement Agreement.

2/ Rule 12.1(c).

In addition, consistent with the Settlement Agreement, the Settling Parties ask for immediate ALJ's Ruling(s) to do the following:

- (1) Include in the issues to be briefed issues associated with encouraging participation in the Demand Response Auction Mechanism (DRAM) Pilot and the potential interaction of other types of Supply Resource solicitation (i.e. outside the DRAM Pilot) with the DRAM Pilot, as set forth in the Settlement Recital, pages 4 to 5, Settlement Section II. C.3.j., page 27, and Settlement III; 15., p 33,^{3/} in addition to the Phase 2 issues related to cost allocation and use of fossil-fueled back-up generators;^{4/} and
- (2) Authorize the three Investor Owned Utilities (IOUs) (PG&E, SCE, and SDG&E) to convene workshops, prior to a final decision, to enable parties and all interested stakeholders to begin working together promptly to design and develop the materials and criteria necessary to timely commence the DRAM Pilot, described in the Settlement Agreement at pages 24 to 30.

II. FACTUAL AND PROCEDURAL BACKGROUND OF PHASES TWO AND THREE

On September 19, 2013, the Commission initiated Rulemaking (R.) 13-09-011 by approving the Order Instituting Rulemaking (OIR) to enhance the role of demand response in meeting California's resource planning needs and operational requirements. The Commission initiated the rulemaking to determine whether and how to bifurcate current utility-administered, ratepayer-funded demand response programs into demand-side and supply-side resources in order to prioritize demand response as a utility-procured resource, competitively bid into the CAISO wholesale electricity market.

3/ As noted in subsection (3) above, the Settlement Parties reached agreement on the use of a DRAM Pilot, but an agreement was not reached on issues related to encouraging participation in that pilot and its interaction with other types of Supply Resources solicitations. To that end, any final resolution of those issues will necessarily require consideration of the briefs that address those issues.

4/ The Settling Parties confirm that this additional issue is within the scope of Phases Two and Three, as identified at page 6 of the Assigned Commissioner and ALJ Ruling and Revised Scoping Memo issued on April 2, 2014.

On November 14, 2013, the assigned Commissioner and Administrative Law Judge (ALJ) jointly issued a Ruling and Scoping Memo (Scoping Memo) that set forth the procedural schedule and scope of issues. The Scoping Memo established a four-phased approach with Phase One dealing with bridge funding issues, Phase Two addressing foundational issues, Phase Three covering future demand response program design, and Phase Four developing a demand response road map. The scope of issues for Phases Three and Four were left to be determined in a later ruling.

On March 27, 2014, the Commission issued a decision (D.14-03-026) on the Phase Two foundational issues. By that decision, the Commission determined that demand response programs should be bifurcated into load modifying resources and supply resources, that a proposal for a demand response auction mechanism would be provided in a future ruling, and that other foundational issues would be addressed in future decisions.^{5/}

On April 2, 2014, the Assigned Commissioner and ALJ issued their joint ruling providing a Revised Scoping Memo for Phases Two and Three (April 2 ACR). The April 2 ACR identified the scope of the remaining Phase Two (“foundational”) issues and the scope of Phase Three. The remaining Phase Two issues include: a review of cost allocation/cost recovery, the use of fossil-fueled back-up generation for demand response, and revisions to the cost-effectiveness protocols.^{6/} The Phase Three issues were divided into the following topic areas: Goals for Demand Response, Resource Adequacy Concerns, CAISO Market Integration Costs, Supply Resources Issues, Load Modifying Resources Issues, and Program Budget Application Process.^{7/} In addition, the April 2 ACR included the proposed Demand Response Auction Mechanism (DRAM) in Attachment B to that ruling. Parties were directed to address the issues identified within the scope of Phases Two and Three, along with the proposed DRAM, in their testimony to

5/ D.14-03-026, at pp. 2, 23-25.

6/ April 2 ACR, at pp. 3, 6.

7/ April 2 ACR, at pp. 4-6.

be served in May 2014. Further, Attachment A of the April 2 ACR provided guidance for that testimony in the form of questions on each Phase Two and Phase Three issue area.

Attachment A did not include questions on issues related to cost-effectiveness protocols. Instead, a further and separate process was identified for addressing those issues. As such, cost-effectiveness protocols were not an issue area for testimony or hearings on Phase Two and Phase Three issues, or for the subsequent settlement discussions described below.

Specifically, on June 23, 2014, the ALJ issued a Ruling Requesting Comment on Proposed Revisions to the Cost-Effectiveness Protocols. Those revisions consisted of an Energy Division Staff Proposal, dated April 25, 2014, and attached to the June 23 ALJ's Ruling as Attachment A. That Ruling directed parties to file Opening and Reply Comments on Attachment A on August 15 and August 22, 2014, respectively.

With respect to the testimony on the other Phase Two issues (cost allocation/recovery and BUGS) and the Phase Three issues, the following parties served Opening Testimony on May 6, 2014: PG&E, SCE, SDG&E, CAISO, ORA, TURN, CLECA, DACC/AReM, MCE, Joint DR Parties^{8/}, EnergyHub/Alarm.Com, OPower, Inc., Natural Resources Defense Council (NRDC), Sierra Club, and Clean Coalition.^{9/} On May 22, 2014, rebuttal testimony was served by PG&E, SCE, SDG&E, CAISO, ORA, TURN, CLECA, DACC/AReM, MCE, DR Parties, and Clean Coalition.

Prior to the start of evidentiary hearings scheduled for the week of June 9, 2014, the ALJ determined, in response to input from the parties, that a portion of that week should be devoted to Workshops on certain topics, rather than hearings. On June 5, 2014, the ALJ announced a schedule for that week to begin with a limited evidentiary hearing on the morning of June 9 to permit cross-examination of SDG&E witness James Avery and identification and admission into

8/ The Joint DR Parties are EnerNOC, Comverge, and JCI.

9/ Calpine Corporation also served testimony on May 6, 2014 and May 22, 2014, although it is not on the service list for R.13-09-011.

evidence of certain exhibits.^{10/} The evidentiary hearings were then recessed to commence workshops that ultimately continued through June 11, 2014. The topics addressed at those workshops included BUGS, CAISO integration costs, characteristics of load modifying versus supply resources, demand response goals, DRAM, and the interplay of DRAM with Resource Adequacy (RA).

On June 12, 2014, the ALJ called a second brief evidentiary hearing to mark for identification certain additional exhibits and consider next steps in the proceeding, including setting future hearing dates for July 10 and 11.^{11/} Upon adjournment of that hearing, a settlement discussion, pursuant to Rule 12, commenced. Based on input from the parties engaged in settlement, the ALJ issued an email ruling on June 23, 2014, removing the July 10 and 11 hearing dates from the calendar and setting a PHC for July 29 to be followed, as necessary, by hearings scheduled for August 7 and 11, 2014.

At the July 29, 2014 Prehearing Conference in Phases Two and Three (July 29 PHC), the Settling Parties reported on the status of settlement discussions without addressing any confidential terms, but did provide a description of the Settling Parties' compliance to that date with Rule 12 and an expected filing date for this Motion and the Settlement Agreement on or about August 1, 2014. In addition, the ALJ and the parties discussed the next steps. The ALJ made a direct inquiry as to whether any party intended to raise a material contested issue of fact that could require a hearing on the Settlement Agreement under Rule 12.3; no party indicated that such a material contested issue of fact existed.^{12/} The Settling Parties, however, stated that

10/ Exhibits SGE-01, SGE-02, SGE-03, SGE-04, SGE-05, SGE-06, MCE-01, DAC-01, DAC-02, NRD-01, CLC-01, CLC-02, DAC-01, and DAC-02 were marked for identification; and Exhibits SGE-01, NRD-01, CLC-01, DAC-01, and DAC-02 were accepted into evidence.

11/ Exhibits ISO-01, ISO-02, ISO-03, ISO-04, ISO-05, ISO-06, CPC-01 43, CPC-02 43, CLE-01, CLE-02, CLE-03, CLE-04, CLC-02A, EDF-01, EDF-02, EDF-03, JDP-01, JDP-02, JDP-03, JDP-04, JDP-05, ORA-01, ORA-02, ORA-03, PGE-01, PGE-02, PGE-03, PGE-04, PGE-05, PGE-06, PGE-07, SGE-07, SGE-08, SGE-09, SGE-10, SGE-11, SGE-12, SGE-13, SCL-01, SCE-01, SCE-01A, SCE-02, SCE-02A, TRN-01, TRN-01A, TRN-02, TRN-02A, TRN-03, TRN-03A, TRN-04, and TRN-05 were marked for identification. The following exhibits also were received into evidence: CLE 04, SGE 02, SGE 03, SCL-01, and CLC-02A that day.

12/ Reporter's Transcript (RT) at 114 (ALJ Hymes).

they were prepared to provide a panel of representatives to respond to informational or clarification questions from the ALJ.

On July 31, 2014, ALJ Hymes issued an electronic ruling (July 31 ALJ's Ruling), which, based on input received at the July 29 PHC, revised the schedule of this proceeding to require (1) Opening Briefs and Opening Comments on the Settlement Agreement to both be filed on August 25, 2014; and (2) Reply Briefs and Reply Comments on the Settlement Agreement to both be filed on September 8, 2014. Given that this schedule shortens the time otherwise permitted for Comments on a settlement, the ALJ set August 4, 2014, as the due date for any objections to that shortened time being sent by electronic mail to the ALJ. Absent objections, the ALJ's Ruling determines "the shortened comment period to be reasonable."^{13/}

In addition, the July 31 ALJ's Ruling set August 11, 2014, as a Status Conference, for the purpose of a panel of Settling Parties to provide an overview of the Settlement Agreement to the ALJ. The July 31 ALJ's Ruling also advised that further guidance regarding the testimony and the need for additional hearings would be provided at a later date, and comment dates previously set for responding to proposed revised cost-effectiveness protocols (August 15 and August 22, 2014) were suspended until further notice.

Finally, the July 31 ALJ's Ruling also directed that "the settlement document should also contain a comparison exhibit that provides a list of the issues from the April 2, 2014 ruling and Revised Scoping Memo, parties' original positions from testimony, and the outcome as agreed upon in the settlement."^{14/} This Motion and the Settlement Agreement set forth in clear detail how the Settling Parties approached the Phase Three issues, including how each identified "Issue Area" matched to the topics identified as being within the scope of Phase Three.^{15/} One of the primary changes that occurred, however, as a result of the June 9 through June 11 Workshops was the emergence of an understanding of the Phase Three Issues that required both an

13/ July 31, 2014 ALJ's Ruling.

14/ Id.

15/ See, Sections IV below.

articulation and resolution of those issues in a manner that was different than reflected in the testimony “guidance” provided by Attachment A of the April 2 ACR.

As a result, in many cases, the issues and their resolution are different from the precise manner in which they were addressed in the Settling Parties’ testimony. This outcome was necessitated by, again, a greater understanding of both the facts and current and future regulatory paradigms that impact these issues.

The Settling Parties are submitting as Attachment B to this Motion a Comparison Exhibit containing brief descriptions of the opening testimony submitted by service list parties on the Phase Three issues in the April 2 ACR in compliance with the July 31 ALJ Ruling. The Comparison Exhibit also provides brief summaries of the Settlement Agreement outcomes for the Phase Three issues. The Settling Parties believe that the attached Comparison Exhibit fulfills the intent of the ALJ’s request in her July 31, 2014 e-mail ruling.

III. SETTLEMENT HISTORY AND RULE 12 COMPLIANCE

Upon adjournment of the evidentiary hearing on June 12, 2014, parties to this proceeding began settlement discussions on the issues identified by the April 2 ACR as within the scope of Phase Two and Phase Three. Those discussions extended through many weeks, including in-person meetings, email correspondence, and conference calls.

At all times during these meetings and discussions, the Settling Parties have fully complied with Article 12 (Settlements) of the Commission’s Rules of Practice and Procedure. Among other things, all participating parties complied with and were bound by the Confidentiality and Inadmissibility provisions of Rule 12.6, holding all such discussions confidential and agreeing not to disclose them outside the negotiations without the consent of participating parties.

Further, prior to signing the Settlement Agreement, the Settling Parties convened a Settlement Conference on July 23, 2014, with notice and opportunity to participate provided to all parties to this proceeding more than three weeks in advance on June 27, 2014. On July 23,

the Settlement Conference was held at the Commission's offices, and the proposed Settlement Agreement was described and discussed. After the conclusion of the Settlement Conference, the Settlement Agreement was finalized and executed as of August 1, 2014, and has been offered for Commission consideration and adoption by this Motion today, August 1, 2014.^{16/} In this regard, the Settlement Agreement complies with Rule 12.5 in recognizing that Commission adoption of the Settlement Agreement, while binding on all parties to this proceeding, does not constitute precedent regarding any principle or issue in this proceeding or in any future proceeding.

IV. CONTEXT, SCOPE, AND SUMMARY OF SETTLEMENT AGREEMENT

A. Settlement Context

In D.14-03-026, the Commission adopted conceptual bifurcation of the Commission-regulated demand response (DR) portfolio of programs into two categories: (1) load modifying resources, which reshape or reduce the net load curve; and (2) supply resources, which are integrated into the CAISO energy markets.^{17/} In adopting its DR bifurcation policy, however, the Commission made clear that it did not intend to favor one category over another, but rather:

“[T]he Commission's goals are to improve the efficiency of demand response and increase the use of all demand response programs; but there is no intention to diminish the value of demand response in either category.”^{18/}

The Commission further affirmed that, “as has been echoed by several parties during this proceeding, the Commission will insure that we do not devalue current demand response programs.”^{19/}

The Settling Parties are mindful of the cited Commission statements regarding demand response, the current programs, and the goal of avoiding diminution of the value of demand

16/ Rules 12.1(a) and (b).

17/ D.14-03-026, at p. 1.

18/ D.14-03-026, at p. 2. In addition, the Commission reiterated its intent at page 7 of D.14-03-026, as follows:

19/ D.14-03-026, at p. 6.

response, whether load modifying resource or supply resource. However, the Settling Parties agree that information and insights that came to light during the workshops, hearings, and settlement discussions that took place in June and July 2014 have revealed that the course set via the topics and testimony guidance identified in the April 2 ACR for implementing bifurcation could actually lead to results that would be counter to the Commission's stated intentions.

Specifically, the Settling Parties learned many critical things about what is necessary to increase demand response successfully in a future world where DR Supply Resources are bid directly into the CAISO market by third-party DR providers, as well as the utilities. It became apparent to the Settling Parties that rushing into bifurcation implementation without addressing and solving valuation, integration, process, and cost questions that emerged in both the workshops and settlement discussions in June and July 2014 will set back and diminish demand response and not improve and increase DR as expected by the Commission. In fact, consistent with the Commission's stated intentions in D.14-03-026, such a result (a decrease or diminishment of DR) would clearly be an unintended consequence that should be addressed and avoided.

To that end, the Settling Parties first sought to identify "Issue Areas" in a manner consistent with the actual challenges faced in bifurcating DR resources and moving toward CAISO integration and further agreed that a deliberate, measured approach to implementing bifurcated demand response and direct participation in the CAISO market was required.^{20/} As explained in more detail below, the Settlement Agreement has in turn been based on these identified Issue Areas for moving forward, rather than directly responding to the questions or testimony guidance included in Attachment A or the DRAM proposal as specifically provided in Attachment B of the April 2 ACR.

20/ In addition, the Settling Parties noted that changes and implementation to the cost effectiveness protocols that are used to evaluate demand response programs would likely be important for future demand response. On June 23, 2014, the ALJ issued a Ruling Requesting Comments on Proposed Revisions to the Cost-Effectiveness Protocols, which included a draft set of revisions to the protocols attached to the ruling. Thus, cost effectiveness protocols are being considered separately and were not included in the scope of issues considered for this settlement.

B. Settlement Scope (“Issue Areas”)

During the initial settlement discussions, the Settling Parties, for the reasons described above, developed “Issue Areas” in order to reach outcomes that would further align with the Commission’s policy conclusions reached in D.14-03-026. Ultimately, the Issue Areas that moved to settlement do not include any Phase Two issues, but do seek to resolve all Phase Three issues.

1. The Settlement Agreement Does Not Address or Resolve the Remaining Phase Two Issues.

The three remaining Phase Two issues were generally described by the April 2 ACR as (1) revisions to the DR cost-effectiveness protocols, (2) review of cost allocation/recovery, and (3) use of fossil-fueled back-up generators.^{21/} None of these issues are included in the Settlement Agreement and their treatment, separate from the agreement, can be summarized as follows:

- *Revision of Cost-Effectiveness Protocols*: During the week of June 9, 2014, parties to this proceeding were advised that revised cost-effectiveness protocols would be issued for party comment at a later date. That action was taken by ALJ’s Ruling issued on June 23, 2014 (June 23 ALJ’s Ruling), which summarized and attached draft revisions to the 2010 Cost-Effectiveness Protocols as proposed by Commission Staff, and offered the opportunity for parties to file Opening and Reply Comments on August 15 and August 22, respectively. Given this separate and ongoing process adopted for this issue, any such revisions are not part of the Settlement Agreement.
- *Review of Cost Allocation/Recovery*: This issue was included in the initial phase of the settlement discussion. However, following confidential discussions among interested parties, it was reported that no agreement could be reached and that the issue should be briefed instead, according to the schedule adopted by the ALJ. As a result, this issue is not part of the Settlement Agreement.
- *Use of Back-Up Generators*: During public Workshop discussions on June 12, 2014, parties agreed that this issue did not require further evidentiary hearings, but, instead,

21/ April 2 ACR, at p. 6.

should be addressed in briefs. The issue was, therefore, never included in the settlement discussions and is not part of the Settlement Agreement.

2. The Settlement Agreement Addresses All Phase Three Issues by “Issue Area.”

To further and comply with Commission policy adopted in D.14-03-026, the following “Issue Areas” were developed by the Settling Parties to reach a Settlement Agreement on all issues identified as being within the scope of Phase Three of this proceeding by the April 2 ACR. These Issue Areas are collectively Issue Areas 1, 2, 3, 4 and 5 and are described as follows:

Issue Area #1: Demand Response Goals,

Issue Area #2: Valuation/Program Categorization,

Issue Area #3: Demand Response Auction Mechanism (DRAM), Utility Roles, Future Procurement,

Issue Area #4: CAISO Integration,

Issue Area #5: Budget Cycles

The Settling Parties sought to ensure that each Issue Areas was responsive to the scope identified by the April 2 ACR for Phase Three, including consideration of the Demand Response Auction Mechanism (DRAM). In this regard, the Issue Areas can be matched to those topics as identified by the April 2 ACR at pages 4 through 6 and Attachment B as follows:

- “Goals for Demand Response” [**Issue Area #1**]
- “Resource Adequacy Concerns (as directed by D.14-03-026)” [**Issue Area #2**]
- “CAISO Market Integration Costs (as directed by D.14-03-026)” [**Issue Area #4**]
- “Supply Resource Issues” [**Issue Area #2**]
- “Load Modifying Resource Issues” [**Issue Area #2**]
- “Program Budget Application Process” [**Issue Area #5**]
- DRAM (included in the April 2 ACR as Attachment B) [**Issue Area #3**]

C. Summary of Settlement Agreement

1. Overview

The Settlement Agreement includes both recitals and terms and conditions that address and resolve the Issue Areas identified above as follows: Demand Response Goals (Issue Area #1); DR Valuation and Program Categorization (Issue Area #2); DRAM, Utility Roles, and Future Procurement (Issue Area #3); CAISO Integration (Issue #4); and Budget Cycles (Issue Area #5). While all of these terms and conditions are interrelated and represent compromise by the Settling Parties on all of these issues as a whole, two of the Issue Areas (Issue Area #2 (Valuation and Program Categorization) and Issue Area #4 (CAISO Integration)) lent themselves to further integration into one section of the Terms and Conditions of the Settlement Agreement.

A high level summary of the Terms and Conditions reached on the designated Issue Areas is provided below. However, a full understanding of all compromises reached requires review and consideration of each Term and Condition of the Settlement Agreement. Finally, taken as a whole, the Settlement Agreement represents the Settling Parties' agreement on the manner in which we believe the Commission should resolve these Issue Areas today to allow for a reasonable transition to a competitive market for DR supply resources that does not diminish, but instead improves and increases the level of all DR resources available to meet both current and future energy needs.

2. By "Issue Area"

a. Issue Area #1: Demand Response Goals

Using available information about current demand response aspirational goals and the current level of demand response, the Settling Parties have agreed to an interim statewide demand response goal and a process and criteria for establishing firm demand response goals that resolves the set of issues set forth in the April 2 ACR Scope. The Settlement Agreement specifies the criteria for a firm DR goal and a timetable and process, including the development and completion of a DR Potential Study, to inform the adoption of a firm DR goal specific to each utility.

b. Issue Area #2: Valuation/Program Categorization, and Issue Area #4: CAISO Integration

During settlement discussions, the Settling Parties concluded that D.14-03-026 provided a sufficient framework for demand response program categorization, but that the value proposition for both Load-Modifying Resources and Supply Resources extended beyond resource adequacy. Further, the Settling Parties concluded that the issues of program categorization and valuation (Issue Area #2) were interrelated with those arising from CAISO integration (Issue Area #4).

For purposes of this high level summary, the Settling Parties first acknowledged that DR program bifurcation would begin in 2017, with new and redesigned programs offered by the IOUs in their DR Budget Applications to be submitted in November 2015. With that in mind, the Settling Parties concluded that these new or redesigned programs should have the necessary characteristics to meet specific pre-determined needs as either Supply Resource or Load-Modifying Resource DR, but that further analysis is required pursuant to a process and timetable included in the Settlement Agreement. During the pendency of that work, the current valuation used to calculate the system and local resource adequacy credits for the IOUs' existing DR programs will be retained through 2019.

With respect to the costs of integrating Supply Resources into the CAISO market, the Settling Parties recognized that there is experience to be gained from current efforts to bring existing programs into the market, and these efforts will continue beyond the anticipated issuance of a decision on Phase Three issues in December 2014. The Settling Parties concluded that a better understanding of costs, existing barriers to CAISO integration, and possible resolution would be facilitated by further dialogue, particularly because these issues are technically complex and could not be easily resolved in the context of either hearings or in the Settlement Agreement. To that end, the Settlement Agreement specifies a process and timetable, including working groups and applicable charters, for that purpose.

c. Issue Area #3: Demand Response Auction Mechanism (DRAM), Utility Roles, Future Procurement.

The Settling Parties concluded that changes in the requirements for direct participation by demand response providers in the CAISO market are needed to reduce the cost and complexity of that participation without creating operational difficulties for the CAISO. The resolution of those integration issues is central to the development of the DRAM, the purpose of which is to competitively procure Supply Resources that will be integrated into the CAISO markets. Such integration will, in turn, require auction winners to make the substantial investment in up-front costs to meet all CAISO and CPUC integration requirements. The Settling Parties also recognize that many issues must be resolved in order for the DRAM to be implemented, including bidding rules, cost caps, and payment structure.

With that in mind, the Settling Parties have agreed that resolution of these issues requires, and would be benefitted by, DRAM Pilot auctions, the first of which would be held in 2015 for 2016 delivery of supply resource DR and the second would be conducted in 2016 for deliveries beginning in 2017. Each auction would be for a minimum of 22 MW statewide, apportioned among the IOUs, as reflected in the Settlement Agreement except that if a utility's DRAM contract(s) from the first auction includes MW commitments after 2016, the MWs from the first auction that continue after 2016 will count towards that utility's MW minimum for the second auction. The IOUs' costs for the DRAM pilot would be recorded in existing DR related balancing accounts, provided the funds are not spent or committed and that the IOUs are authorized to shift funds for this purpose without the limitations of the existing fund shifting rules as defined in D.12-04-045 (Ordering Paragraph 4).^{22/} The allocation of costs among customers of the 2015-2016 DRAM Pilot-related amounts as well as DRAM-related amounts in 2017-2019 shall be subject to briefing and determination by the Commission in this proceeding.

^{22/} If sufficient bridge funding is not available to fund incentives for approved DRAM Pilot contracts in 2016, funding for those incentives could be addressed in the advice letters that the utilities would have to file after the winners of the DRAM auction are determined.

The Settling Parties agreed that a broad, public stakeholder process or working groups, convened by December 2014, should be used to develop the design, protocol, and standard offer contracts of the DRAM Pilot. The resulting DRAM Pilot design, protocol and standard offer contracts would be submitted to the Commission for its review and approval. The winning contracts in the DRAM Pilot also would be submitted to the Commission for approval. The Settling Parties further agreed that, at the same time, the IOUs will have the option of conducting RFOs in 2015 for delivery in 2017 and beyond for supply resource and load-modifying DR that differ from those procured through the DRAM pilot. However, the Settling Parties could not reach agreement on the specifics of how to encourage participation in the DRAM Pilot and consider the related impact of the RFOs, but did agree to that issue being the subject of briefs.

For the period 2015-2016, the Settling Parties agree that costs for the DRAM Pilot will be recovered through bridge funding authorized in D.14-01-004 and D.14-05-025. In order to use the 2015-2016 bridge funding for the DRAM Pilot, the IOUs need the Commission to: 1) determine that funding the DRAM Pilot from previously authorized bridge funding budgets is appropriate, and 2) authorize the IOUs to shift funds for the purpose of funding the DRAM Pilot without the limitations of existing fund-shifting rules as defined in D.12-04-045, Ordering Paragraph 4. If 2015-2016 bridge funding is insufficient to recover the incentives paid in 2016 to winning bidders in the DRAM Pilots, the IOUs would be permitted to request recovery of the incentives in the advice letter(s) submitting the winning DRAM Pilot contracts for approval.

d. *Issue Area #5: Budget Cycle*

The Settling Parties agreed that the development of an extended budget cycle required careful consideration and needed to be coordinated with other changes to DR programs and procurement taking place today. The Settling Parties therefore agreed that there should be one more three-year program cycle (2017-2019), with certain mid-cycle reviews, before a longer budget cycle goes into effect, and also agreed on a process to develop the appropriate rules for a

potential extended DR budget cycle. That process would be initiated by April 1, 2015, and coordinated with the IOUs' Rule 24/32 and other Commission and CAISO stakeholder processes, with the goal of offering proposed rules by December 31, 2015, for Commission approval by March 31, 2016.

V. THE SETTLEMENT AGREEMENT IS REASONABLE, CONSISTENT WITH THE LAW, IN THE PUBLIC INTEREST, AND SHOULD BE ADOPTED BY THE COMMISSION.

The Commission will approve a settlement if it finds the settlement “reasonable in light of the whole record, consistent with law, and in the public interest.”^{23/} As a matter of public policy, the Commission generally favors settlements of disputes if they are fair and reasonable in light of the record, finding that such a policy “supports worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce an unacceptable result.”^{24/}

Thus, in reviewing a settlement, the Commission will consider (1) the risk, expense, complexity and likely duration of further litigation, (2) whether the settlement negotiations were at arms-length, (3) whether major issues were addressed, and (4) whether the parties were adequately represented.^{25/} Further, while the Commission considers individual settlement provisions, “in light of the strong public policy favoring settlements, we do not base our conclusion on whether any single provision is necessarily the optimal result,” but “whether the settlement as a whole produces a just and reasonable outcome.”^{26/} Finally, the Commission will also consider and approve settlements that are not joined by all parties where the settlement taken as a whole is in the public interest and generally balances the various interests at stake in a manner consistent with the applicable policy objectives and law.^{27/}

23/ Rule 12.1(d); *see also* D.09-10-017 (applying Rule 12.1(d) criteria).

24/ D.11-12-053, at p. 72.

25/ Re Pacific Gas & Electric Company, 30 CPUC 2d 189, 222.

26/ D.11-12-053, at p. 73.

27/ D.11-12-053, at p.76.

The Settlement Agreement on Phase Three issues readily meets all of the applicable criteria set forth in Rule 12 for Commission adoption. To begin with, the Settling Parties included nearly all parties that offered testimony on Phase Three issues. Further, the interests represented by the Settling Parties are divergent and broad based, and the Settlement Agreement reflects both accommodation and compromise of positions held by each of the Settling Parties.

In reaching the Settlement Agreement, each of the Settling Parties were adequately represented, negotiated in good faith and at arms-length, bargained aggressively, compromised, and agreed to the Settlement Agreement as an interrelated package of terms and conditions on Phase Three issues. The resolution of any one term or Issue Area cannot be assessed separately or discretely. Instead, the Settlement Agreement should be evaluated as a package and with the understanding that any change by the Commission to the settled resolution of any one issue or Issue Area may undermine or upset the balance of positions that the entire package strikes. Further, the Settlement Agreement, as to its individual terms and as a whole, considered all available information and the record to date on DR programs, valuation, and procurement; agreed to terms consistent with that information and the law, and balanced the various interests at stake and reached outcomes consistent with the applicable policy objectives for DR.

In terms of the issues addressed, the record in this case – from the testimony served and identified in May and June 2014 to the Workshops and hearings held the week of June 9 – makes very clear that the Phase Three issues are contentious and complex and reflect fundamental changes in how demand response resources are to be valued, categorized, and procured going forward. There is no doubt, as became apparent in the transition from hearings to workshops in June 2014 to facilitate even a basic understanding of these issues, that a reasonable and fair resolution of these issues would not be achieved by litigation. Instead, litigation would be time consuming and expensive and risk reaching “unacceptable results” at odds with applicable Commission DR policy.

For these reasons, the Settling Parties ask that the Commission find that the Settlement Agreement complies with all of the requirements of Rule 12 (see, Section III. B., *supra*) and is

reasonable in light of the whole record, consistent with the law, and in the public interest. With those findings, the Settlement Agreement should be adopted by the Commission without revision.

VI. RULE 12.3 HEARINGS ARE NOT REQUIRED

Rule 12.3 allows the Commission to “decline to set hearing” on a Settlement Agreement “[i]f there are no material contested issues of fact, or if the contested issue is one of law.” In this case, as recited above, the settlement discussions were open to all parties with an interest in resolving issues within the scope of Phases Two and Three. Further, in compliance with Rule 12, a Settlement Conference was properly noticed to all parties to this rulemaking and held on July 23, 2014, at which the Settling Parties described to inactive parties the Settlement in detail, and no one stated their intent to raise a material contested issue of fact related to the Settlement Agreement. Further, at the July 29 PHC, ALJ Hymes asked if any party had a material contested issue of fact related to the Settlement Agreement, and no party responded in the affirmative.^{28/}

It is the Settling Parties’ position that the Settlement Agreement does not raise any material contested issues of fact that would require the Commission to hold an evidentiary hearing on the Settlement Agreement pursuant to Rule 12.3. Further such a hearing would prevent the expeditious review of the Settlement Agreement and, in turn, the timely resolution of Phase Three by December 2014 as intended by the Commission. However, the Settling Parties, as indicated at the July 29 PHC, will make a panel of representatives available to the ALJ for information or clarification questions. That panel has been scheduled to appear before ALJ Hymes on August 11, 2014.

VII. ADDITIONAL REQUESTED RELIEF IN FURTHERANCE OF THE SETTLEMENT AGREEMENT

As referenced above, certain Phase Two issues have already been identified as outside the Settlement Agreement and, while not requiring evidentiary hearings, will be the subject of briefs.

28/ RT at 114 (ALJ Hymes).

In addition, while the Settlement Agreement did address all Phase Three issues, its proposal of a DRAM Pilot raised an issue on which the parties could not reach an agreement on its resolution, but did reach an agreement that, instead, the issue could be the subject of briefs.

Because of these circumstances, the Settling Parties request that an ALJ's Ruling be issued immediately to confirm that the issues to be briefed in the Opening and Reply Briefs, now due on August 25 and September 8, respectively, include all of the following issues:

- (1) The remaining Phase Two issues of cost allocation;
- (2) The remaining Phase Two issue of the use of back-up generators; and
- (3) Issues associated with encouraging participation in the Demand Response Auction Mechanism (DRAM) Pilot and the potential interaction of other (i.e. non-DRAM Pilot) solicitations for Supply Resources with the DRAM Pilot, as set forth in the Settlement Agreement.^{29/}

In addition, to permit prompt development of the DRAM Pilot as identified in the Settlement Agreement, an ALJ's Ruling is required prior to a final decision to authorize PG&E, SCE, and SDG&E to convene workshops to enable all parties, interested stakeholders, and entities to begin the work necessary to develop the DRAM Pilot design, including DRAM RFO solicitations, protocols, standard contracts, and other DRAM Pilot Design matters, as soon as possible. This ruling is necessary to timely commence the DRAM Pilot, as described in the Settlement Agreement and for timely submission to the Commission before the first auction, as anticipated in Attachment B, Page 15, to the April 2 ACR.

Further, because the funding of the DRAM requires modifications to the earlier bridge funding and fund shifting decisions, the Settling Parties ask that the final decision approving the settlement determine that the DRAM Pilot costs be included among the 2015-2016 DR programs

29/ As noted in subsection (3) above, the Settlement Parties reached agreement on the use of a DRAM Pilot, but an agreement was not reached on issues related to encouraging participation in that pilot and its interaction with Supply Resources RFOs. To that end, any final resolution of those issues will necessarily require consideration of the briefs that address those issues.

to be funded by the budgets authorized in Ordering Paragraphs 10, 15 and 17 of D.14-05-025, which adopted 2015-2016 budgets respectively for PG&E in Attachment 2 , for SDG&E in Attachment 3 and for SCE in Attachment 4 to D.14-05-025, and that the Commission authorize the IOUs to shift funds from existing DR categories to cover the costs of the DRAM Pilot costs, without the limitations of the existing fund-shifting rules contained in D.12-04-045, Ordering Paragraph 4.

VIII. CONCLUSION

As demonstrated above, the Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest. Therefore, the Settling Parties respectfully move for the adoption of the Settlement Agreement (Attachment A hereto) by the Commission without modification. In turn, the Settling Parties request that the Commission base its decision on all Phase Three issues on the Terms and Conditions of the Settlement Agreement. In addition, the Settling Parties request that the ALJ's Rulings detailed in Section V above be issued by the Commission. These rulings are necessary to ensure a full and complete record on remaining Phase Two and all Phase Three issues, consistent with the schedule adopted for those phases in this proceeding.

PG&E is authorized by each of the settling parties to sign this Motion on their behalf.

Respectfully submitted on behalf of the Settling Parties,

/s/Shirley A. Woo

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Date: August 4, 2014

ATTACHMENT A

SETTLEMENT AGREEMENT

**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)

**SETTLEMENT AGREEMENT BETWEEN AND AMONG PACIFIC GAS AND
ELECTRIC COMPANY, SOUTHERN CALIFORNIA EDISON COMPANY, SAN
DIEGO GAS & ELECTRIC COMPANY, CALIFORNIA INDEPENDENT
SYSTEM OPERATOR CORPORATION, OFFICE OF RATEPAYER
ADVOCATES, THE UTILITY REFORM NETWORK, CALIFORNIA LARGE
ENERGY CONSUMERS ASSOCIATION, CONSUMER FEDERATION OF
CALIFORNIA, ALLIANCE FOR RETAIL ENERGY MARKETS, DIRECT
ACCESS CUSTOMER COALITION, MARIN CLEAN ENERGY, ENERNOC,
INC., COMVERGE, INC., JOHNSON CONTROLS, INC., OLIVINE, INC.,
SIERRA CLUB, ENVIRONMENTAL DEFENSE FUND, CLEAN COALITION,
AND ENERGYHUB/ALARM.COM ON PHASE 3 ISSUES**

TABLE OF CONTENTS

	Page
I. RECITALS	2
II. TERMS AND CONDITIONS	12
A. ISSUE AREA #1: DEMAND RESPONSE GOALS	12
B. ISSUE AREA #2: VALUATION/ AND PROGRAM CATEGORIZATION; AND ISSUE AREA #4: CAISO MARKET INTEGRATION COSTS	17
C. ISSUE AREA #3: DEMAND RESPONSE AUCTION MECHANISM, UTILITY ROLES AND FUTURE PROCUREMENT	24
D. ISSUE AREA #4: BUDGET CYCLE	30
III. CONDITIONS	31
IV. REGULATORY APPROVAL	34
V. PERFORMANCE	34
VI. SETTLEMENT EXECUTION BODY TEXT	35
ATTACHMENT A – Charter For Supply Resource Demand Response Working Group	
ATTACHMENT B – Charter For Load Modifying Resource Demand Response Valuation Working Group	
ATTACHMENT C – Charter For Load Modifying Resource Demand Response Operations Working Group	
ATTACHMENT D – Draft Schedule To Complete Two DRAM Auctions	

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INC., COMVERGE, INC., JOHNSON CONTROLS, INC., OLIVINE, INC.,
SIERRA CLUB, ENVIRONMENTAL DEFENSE FUND, CLEAN COALITION,
AND ENERGYHUB/ALARM.COM ON PHASE 3 ISSUES**

In Accordance with Article 12 of the Rules of Practice and Procedure of the California Public Utilities Commission (CPUC or Commission), Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); San Diego Gas and Electric Company (SDG&E); the California Independent System Operator Corporation (CAISO); the Office of Ratepayer Advocates (ORA); The Utility Reform Network (TURN); California Large Energy Consumers Association (CLECA); Consumer Federation of California (CFC); Alliance for Retail Energy Markets (AReM); Direct Access Customer Coalition (DACC); Marin Clean Energy (MCE); EnerNOC, Inc. (EnerNOC); Comverge, Inc. (Comverge); Johnson Controls, Inc. (JCI); Olivine, Inc. (Olivine); Sierra Club (Sierra Club); Environmental Defense Fund (EDF); Clean Coalition (Clean Coalition); and EnergyHub/Alarm.com (EnergyHub/Alarm.com), (jointly, the "Settling Parties"), by and through their undersigned representatives enter into this Settlement Agreement on a mutually agreeable outcome on certain issues in Phase Three of this rulemaking, as described further herein. The issues addressed by this Settlement Agreement were included within the scope of Phase Three of this rulemaking by the *"Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for*

Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings” issued in this rulemaking on April 2, 2014 (“April 2 ACR”).

I. RECITALS

A. *Whereas*, the Settling Parties are all parties of record to Rulemaking 13-09-011 (DR OIR) and include: PG&E; SCE; SDG&E; CAISO; ORA; TURN; CLECA; CFC; ARem; DACC; MCE; EnerNOC; Comverge; JCI; Olivine; Sierra Club; EDF; Clean Coalition; and EnergyHub/Alarm.com.

B. *Whereas*, the factual and procedural background for Phase Two and Phase Three of R.13-09-011 (DR OIR) and the Settlement Agreement are fully described in the accompanying Motion of the Settling Parties for Approval of the Settlement Agreement of Phase Three Issues filed this same day, August 1, 2014 (Settlement Agreement Motion).

C. *Whereas*, the Settlement Agreement Motion describes the history, context, and scope of the Settlement Agreement, a summary of the Settlement Agreement, and the full compliance by the Settling Parties and the Settlement Agreement with all requirements of Article 12 of the Commission’s Rules of Practice and Procedure, and demonstrates and supports findings and conclusions by the Commission that the Settlement Agreement is reasonable in light of the whole record, consistent with law, and in the public interest.

D. *Whereas*, the Settling Parties believe the following recitals will help to clearly identify the treatment of issues on which a settlement has been reached:

1. In the course of the Workshops held on June 9 through June 11, 2014, and the ensuing settlement discussions held over the course of the period from June 12 through July 29, 2014, the Settling Parties learned many critical things about what is necessary to increase demand response (DR) successfully in a future world where third-party DR providers and the investor-owned utilities (IOUs) directly bid supply-side demand response (Supply Resource) into the CAISO market.

2. Based on the evolving understanding of the complex issues presented by this rulemaking, but given the differing views on how to resolve those concerns, the Settling Parties responded to encouragement from assigned Administrative Law Judge (ALJ) Kelly Hymes to meet and pursue a workable compromise and resolution of these issues.
3. With the background of the Workshops and the prepared testimony identified at the evidentiary hearings held on the mornings of June 9 and June 12, 2014, the Settling Parties first created the following issue-based approach for addressing and reaching a mutually agreeable settlement on the Issues for Phase Three identified by the April 2 ACR, using the following “Issue Areas”:
 - Issue Area #1:* Demand Response Goals,
 - Issue Area #2:* Valuation/Program Categorization,
 - Issue Area #3:* Demand Response Auction Mechanism (DRAM), Utility Roles, Future Procurement,
 - Issue Area #4:* CAISO Integration,
 - Issue Area #5:* Budget Cycles
4. The Settling Parties sought to ensure that each of these Issue Areas fell within the scope of, and covered, the Phase Three issues in this proceeding, as follows:
 1. Goals for Demand Response [**Issue Area #1**]
 2. Resource Adequacy Concerns (as directed by D.14-03-026) [**Issue Area #2**]
 3. CAISO Market Integration Costs (as directed by D.14-03-026) [**Issue Area #4**]
 4. Supply Resource Issues [**Issue Area #2**]
 5. Load-Modifying Resource Issues [**Issue Area #2**]
 6. Program Budget Application Process [**Issue Area #5**]
 7. DRAM (included in the April 2 ACR as Attachment B) [**Issue Area #3**]

5. The Settling Parties confirm the settlement discussions considered the interests of all active parties on each Issue Area, and believe the Settlement Agreement addresses each of the Issue Areas in a fair and balanced manner.
6. The Settling Parties represent diverse interests and developed the Settlement Agreement by mutually accepting concessions and trade-offs.
7. The Settlement Agreement strives to enhance the role of DR in California consistent with the Commission's guidance in Decision (D.) 14-03-026 to facilitate direct bidding into the CAISO market and bifurcate DR into Load-Modifying Resources and Supply Resources, while balancing the interests of many parties on multiple issues. This balance has been achieved through the close interrelation of various elements and sections of the Settlement Agreement. Accordingly, the Settling Parties intend that the Settlement Agreement be treated as a package solution, parts of which cannot be altered without affecting the entire agreement.

E. *Whereas*, the Settling Parties acknowledge that two other Issue Areas identified as remaining from Phase Two, specifically, Cost Allocation and the treatment of fossil-fueled Back-Up Generation (BUGs) associated with demand response resources used in conjunction with providing demand response services, have not been settled, and, instead, will be the subject of briefs to be filed according to the schedule established by the ALJ for Phases Two and Three.

F. *Whereas*, the Settling Parties have identified for briefing the following narrowly scoped additional issue: whether the DRAM should be a preferred means of procuring Supply Resources and if so, with respect to encouraging participation in the DRAM Pilot, the potential interaction of IOU solicitations for Supply Resources with the DRAM Pilot and possible limitations on the IOUs' other solicitations for Supply Resources. The Settling Parties' request

for briefing on this narrowly scoped issue is included in the Motion for Approval of this Settlement Agreement.^{30/}

G. *Whereas*, the Settling Parties further acknowledge that another issue remaining from Phase Two, cost-effectiveness protocols, was not an issue for the Workshop or settlement discussions, and is not part of this Settlement Agreement, but will be separately addressed in response to Energy Division’s proposed 2014 Revised Demand Response Cost-Effectiveness Protocols circulated by the ALJ’s June 23, 2014 Ruling. Opening and Reply Comments on the proposal are currently due on August 15 and August 22, 2014.

H. *Whereas*, the terms and conditions of the Settlement Agreement were guided generally by the following:

1. The Commission’s determinations in D.14-03-026 that: (1) it remains the Commission’s goal to improve the efficiency of DR and increase the use of all DR programs, and (2) in adopting its bifurcation of demand response between Load-Modifying Resources and Supply Resources, the Commission did not intend to favor one category over another or diminish the value of demand response in either category or devalue current demand response programs.
2. Information and insights gained during the June 9-11, 2014 workshops and subsequent settlement discussions about CAISO processes, integration efforts, customer operations, and costs to participate, among other things, have revealed that the course set to implement bifurcation via the goals and topics identified in the April 2 ACR could lead to results that would not advance the Commission’s stated intentions to enhance the role of demand response and prioritize demand response.

^{30/} DR Pilots (other than the DRAM Pilot) are excluded from the term “solicitations” for purposes of briefing the narrowly scoped new issue.

3. To avoid rushing into implementation and creating unintended consequences at odds with D.14-03-026, the Settling Parties sought to address and solve valuation, integration, process and cost questions unearthed during Workshops and settlement discussions--difficulties that could diminish DR, instead of increasing and enhancing it to meet future needs. Accordingly, the Settling Parties have generally agreed to a measured approach to implementing bifurcated DR and direct participation in the CAISO market and have reached a Settlement Agreement on the issue areas that focuses on the process for going forward, rather than responding specifically to the questions in Attachments A or B of the April 2 ACR.

I. *Whereas*, in addition to the April 2 ACR and its Attachments, the terms and conditions of the Settlement Agreement were guided more specifically by the following considerations applicable to each specific Issue Area:

Whereas, as to **Issue Area #1: Demand Response Goals**, the Settling Parties were guided by the following, in addition to the April 2 ACR and Attachment A thereto:

1. Existing Aspirational Goal: The Energy Action Plan (EAP) established an aspirational goal for statewide DR of 5% of peak load to come from price response by consumers by 2007.^{31/} However, a later update of the EAP confirmed that, as of February 2008, “[w]e are nowhere near that goal and must reinvigorate our efforts in this area.”
2. Current Level of Demand Response: Based on the IOUs’ load impact reports filed in April 2014, using a 1 in 2 year average weather assumption, and using IOU peak demands as identified in the California Energy Commission (CEC) 2013 Integrated Energy Policy Report (IEPR)^{32/}, the Settling Parties

^{31/} See, EAP II (http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf), at p. 7; 2008 EAP Update (http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF), at p. 10.

^{32/} The 2013 IEPR was adopted in January 2014 and slightly revised in February 2014.

concluded that statewide, event-based demand response, including reliability programs, currently comprises approximately 3.9% of the sum of the individual system peak demands of SCE, SDG&E and PG&E.^{33/}

3. Given the existing DR aspirational goals and the current level of DR, the Settling Parties have agreed to an interim DR goal and a process and criteria for establishing firm DR goals that resolve the issues set forth in the April 2 ACR. The Settling Parties recognize that using the sum of the individual IOUs' peak demands in setting an interim goal is for the purposes of quantifying DR levels and is not intended to reflect the manner in which DR resources will actually be used to meet system, local, distribution level, or flexibility needs.

Whereas, as to **Issue Area #2: Valuation and Program Categorization** and **Issue Area #4: CAISO Market Integration Costs**, the Settling Parties were guided by the following, in addition to the April 2 ACR and Attachment A thereto:

1. The April 2 ACR included many issues associated with DR program categorization and characteristics, while the program valuation issues focused mostly on Resource Adequacy (RA) concerns. The Settling Parties concluded that D.14-03-026 provided a sufficient framework for DR program categorization, but that the valuation issues for both Load-Modifying Resources and Supply Resources extended beyond RA.
2. D.14-03-026 determined that Supply Resources are “resources that are integrated into the energy markets (CAISO),” while Load-Modifying

^{33/} For PG&E, SCE and SDG&E, respectively, the calculation of event-based, including reliability, DR from the April 2014 Load Impact Reports is divided by the sum of the IOUs' System Peak Demands, as reflected in the April 2014 Integrated Energy Policy Report (IEPR) is as follows: $(626+1318+85)/(24100+23200+4830)=2029/52130=3.9\%$

Resources “re-shape or reduce the net load curve.” The Settling Parties concur that Supply Resources that are fully integrated into the CAISO market and meet requisite CPUC resource adequacy requirements should receive RA credit just like conventional resources. However, the Settling Parties recognized that Load-Modifying Resources can reduce RA requirements but that RA is only one component of value for DR resources; other values beyond RA value (for example, avoiding or deferring the need for distribution facilities, improving the operational efficiency of either or both transmission and distribution facilities, integrating renewable resources), should be accounted for as part of the valuation proposition.

3. D.14-03-026 directed that DR program bifurcation begin in 2017 with the next demand response program application cycle, and that the IOUs will submit applications for new or redesigned programs in November 2015. The Settling Parties concluded these new or redesigned programs should have the characteristics necessary to meet specific pre-determined needs as either Supply Resources or Load-Modifying Resources and that the ultimate goal for any demand response program should be to cost-effectively avoid or reduce electric system costs and comply with the EAP Loading Order. They also concluded the current methodology used to calculate the system and local RA credits for the IOUs’ existing DR programs should be retained through 2019.
4. With respect to the costs of integrating Supply Resources into the CAISO market, the Settling Parties recognized experience can be gained from current efforts to bring existing programs into the market, and these efforts will continue beyond the anticipated date for a decision on Phase Two and Phase Three issues in this docket. The Settling Parties concluded these integration issues are technically complex and not well suited for resolution through

hearings or in the context of this Settlement Agreement, and further dialogue is necessary to create better understanding of costs, existing barriers to CAISO integration and possible resolution.

Whereas, as to **Issue Area #3: Demand Response Auction Mechanism (DRAM), Utility Roles, and Future Procurement**, the Settling Parties were guided by the following, in addition to the April 2 ACR and Attachment B thereto:

1. Workshops and settlement discussions enabled the Settling Parties to share information and insights from different stakeholder groups on what would be needed to successfully procure Supply Resources through an auction mechanism involving third party direct participation in CAISO markets.
2. In workshops and settlement discussions, parties discussed proposals to change some of the requirements associated with bidding Supply Resources into the CAISO market in ways that could reduce cost and complexity without creating any operational difficulties for the CAISO. Agreement on modifications to these various requirements for direct participation, and their adoption by CAISO and the Commission, would significantly facilitate participation by third parties using retail load for DR. However, reaching agreement on these modifications and having them adopted by the CAISO and the Commission will take some time. The Settling Parties understand the Commission's wish to implement integration as quickly as possible, but also believe that success will require substantially reducing the costs and complexity of integration.
3. These integration issues are central to the development of the DRAM proposed in Attachment B of the April 2 ACR. The purpose of the proposed DRAM is to competitively procure Supply Resources that will be integrated

into the CAISO markets, including resources from third party DR providers (DRPs). Because the intent of the DRAM is to provide a capacity payment to winning bidders who will be responsible for bidding DR into the CAISO markets, the winners of the auction will have to meet all CAISO and CPUC integration requirements. They will have to be able to make the investment in the up-front costs to perform this integration. Under current requirements, as noted, this will require a substantial investment.

4. There are many issues that have to be resolved in order for the DRAM to be implemented successfully, including bidding rules, cost caps, and payment structure. The Settling Parties propose a DRAM Pilot. This would allow the details of the auction mechanism to be refined with experience.
5. The IOUs may need to conduct non-DRAM RFOs in 2015 for amounts and products beyond the DRAM Pilot auction amounts, because the current Aggregator Managed Portfolio contracts will expire at the end of 2016 (if the Commission approves their extension as provided in D.14-05-025). This would require a RFO in 2015 if these contracts are to be replaced with new contracts that are developed in an adequate time frame for submission and approval by the Commission and implementation by the winning aggregators.
6. Costs incurred to integrate small amounts of DR obtained in the DRAM Pilot into the CAISO market will increase bid prices if bidders must include early integration costs. PG&E is providing integration services for third parties under its IRM2 Pilot using a third-party intermediary, but Settling Parties prefer not to have an IOU involved in the DRAM Pilot winning bidders' integration and scheduling process. The Settling Parties discussed various means of mitigating third party integration costs while preserving competitive neutrality. These include changing the requirements to allow multi-year bids

over which the up-front costs can be amortized, allowing the third parties to share in the costs of using an entity with integration experience for their programs which is not itself a DRP, and/or some level of ratepayer support of integration costs, among others.

Whereas, as to **Issue Area #5: Budget Cycle**, the Settling Parties were guided by the following, in addition to the April 2 ACR and Attachment A thereto:

1. The Settling Parties agree that a DR program budget cycle longer than three years may be appropriate. However, information shared at the workshops and the continuing uncertainty over other critical matters led the Settling Parties to conclude that development of an extended budget cycle requires careful consideration and should be coordinated with other changes currently underway, or pending. Based on these discussions, the Settling Parties propose that there should be one more three-year DR program budget cycle (2017-2019), before a longer budget cycle is considered appropriate.
2. To determine whether an extended budget cycle is appropriate, the Settling Parties are committed to working with the Commission to develop the rules for an extended DR budget cycle and application process for the IOUs for 2020 and beyond, with discussions to begin no later than April 2015. Any proposal developed through this process would be presented to the Commission no later than December 31, 2015 for CPUC approval by March 31, 2016. The Settling Parties anticipate that this schedule will allow sufficient time to assess progress on other matters critical to successful implementation of future DR for direct participation in the CAISO wholesale market.
3. The Settling Parties also anticipate that the process of developing the details of an extended DR budget cycle should produce results that answer the

questions presented in Appendix A to the April 2 ACR including: 1) the length of an extended budget cycle, and 2) how often reviews of IOU DR programs should occur and the appropriate level of scrutiny.

II. TERMS AND CONDITIONS

A. *ISSUE AREA #1: DEMAND RESPONSE GOALS*

Interim and Future Demand Response Goals:

1. In consideration of expected changes in DR programs and customer participation, and the need to conduct a study of DR potential in this State (DR Potential Study), it is appropriate for the Commission to establish and adopt an “interim” DR goal based on the current record of DR programs and participation.
2. Consistent with the criteria and limitations identified in subsections 3 and 4 below, the interim state-wide goal should be 5% of the sum of the peak demands of SCE, PG&E, and SDG&E. The Settling Parties agree that the statewide goal of 5% does not represent an individual goal for any of the IOUs, but rather a collective goal for all of the IOUs. Applying the same statewide goal percentage to an individual utility would not be appropriate because that would not recognize the difference in the DR potential among the IOUs. The Settling Parties agree that, based on the difference between the current DR level of 3.9% and a statewide, event-based goal of 5.0% by 2020, the IOUs will use all good faith efforts to increase levels of event-based DR by approximately 5.1%, on average, each year for five years to reach the 5.0% statewide goal for event-based DR. The Settling Parties agree that this interim goal will support the Commission’s “ultimate goal ... to enhance the role of demand response programs in meeting the state’s long-term clean energy goals while maintaining system and local reliability.”^{34/}

^{34/} R.13-09-011 (DR) Rulemaking, at p. 2.

3. This interim statewide DR Goal should remain in effect until superseded by firm IOU-specific goals subject to the ***Criteria for Establishing Firm Demand Response Goals*** subsection below. The firm goals should be informed by a DR Potential Study discussed in ***Demand Response Potential Study***, below.
4. In sum, the Settling Parties request that the Commission, as part of any decision issued on this topic: (a) adopt an interim statewide DR Goal for cost-effective, event-based DR by 2020 equal to 5% of the sum of the individual peak demands of SCE, SDG&E and PG&E, as described in subsections 2 and 3 above; (b) direct that this interim statewide goal be in effect until superseded by a IOU-specific, firm DR Goal, as described in the ***Criteria for Establishing Firm Demand Response Goals***, and informed by the results of the DR Potential Study to be conducted and developed as described in ***Demand Response Potential Study***, below; (c) adopt a process for the Commission's consideration and implementation of the DR Potential Study process described below; (d) require annual reporting by the IOUs to this Commission, the CAISO, and the CEC of actual IOU event-based DR achieved toward meeting the interim statewide DR Goal and establish a process for measuring performance against the firm goal, which shall include all forms of DR, including non-event based DR; (e) commit to a decision establishing a firm, IOU-specific DR Goal (including non-event based DR) as described in the Criteria for Establishing Firm Demand Response Goals, that will supersede the interim, state-wide goal and is informed by the DR Potential Study, conducted and developed consistent with the titled subsections below, and any responsive comments by stakeholders; and (f) confirm that any firm, IOU-specific DR Goal(s), developed consistent with the titled subsections below, will be subject to reasonable off-ramps.
5. A Commission decision on the firm, IOU-specific DR Goals should also confirm that any update or revision to established firm DR Goal should be utility-specific, depending upon the results of the DR Potential Study, and should include non-event based DR.

Criteria for Establishing Firm Demand Response Goals:

1. A firm, IOU-specific DR Goal must include, and account for, all types of cost-effective DR, whether Load-Modifying Resource or Supply Resource, event-based or non-event-based, emergency or price responsive, that meet DR cost-effectiveness requirements, as applicable. All CPUC-approved DR programs and resource procurement shall count toward that DR goal.
2. The DR Goal shall: (a) reflect the procurement of DR resources in meeting identified needs through solicitations authorized by the Commission in its Long-Term Procurement Planning (LTPP) rulemakings; Resource Adequacy (RA) rulemakings; Demand Response-specific rulemakings or application(s), or other solicitation or program authorizations that include DR resources; (b) ensure that resource solicitations are consistent with Commission authorizations in (a) above and the EAP Loading Order, which requires the procurement of cost-effective energy efficiency and DR first before other resource types, and (c) include other types of needs that the Commission determines may be met by DR.
4. The DR Goal shall not be limited to an impact on “peak requirements” since resource needs are changing and those needs must reflect, and may be dependent on, system (distribution and/or transmission) needs or grid reliability.
5. The DR Goal shall be adapted to each IOU’s current level of DR and its specific characteristics, which includes geographic and customer base considerations. Progress toward the DR Goal will be assessed by using the bridge period years (2015-2016) as the base years.

6. The DR Goal shall not constitute a cap, ceiling, or limitation on the procurement of DR, whether Load-Modifying Resource or Supply Resource, to meet all identified needs included in subsection 2 above and consistent with the EAP Loading Order.
7. During the time when the first Firm DR Goals are in effect, the IOUs shall not be subject to penalties or sanctions for failure to meet the DR Goal or to incentives to meet that goal. Any consideration of possible penalties, sanctions, and incentives for goals after the first Firm DR Goals will be considered as part of the development of these later goals.
8. The IOUs shall report the progress toward meeting the DR Goal on an annual basis on the same date as the annual load impact filing (usually filed April 1st each year). The report shall include information from the IOUs' annual load impact reports, and other appropriate sources. To the extent an IOU is unable to meet its DR Goal, it shall inform the Commission, the CAISO and the CEC, in its annual report and may seek Commission permission to extend the period of time over which the IOU will attempt to meet the goal. The IOU shall identify the cause(s) of not meeting the goal and propose a remedy.
9. The Settling Parties are committed to protecting to the greatest extent possible against erosion of existing overall levels of DR participation.

Demand Response Potential Study:

1. To effectively set a firm IOU-specific DR Goal that supersedes the interim statewide goal, a DR Potential Study is required to determine the amount of DR that is potentially available within certain geographic areas of the State, i.e. IOU service territories, and subject to specific program or resource characteristics, taking into consideration the customer composition and mix of end uses for electricity within those areas. Any existing efforts at the CPUC to study DR potential shall now be informed by the requirements of the DR Potential Study as described herein, including but not limited to the need to conduct a further separate study.

2. The DR Potential Study must be subject to the following:
 - a. The DR Potential Study must incorporate and/or be consistent with the criteria and limitations for a DR Goal identified in the *Criteria for Establishing Firm Demand Response Goals* subsection, above.
 - b. The DR Potential Study, to be well-designed, must: (a) examine the ability for DR resources to meet a broad range of operational needs of the CAISO and the IOUs; (b) examine all forms of DR that may be available to the IOUs or CAISO as either Supply Resource or Load-Modifying Resource, event-based and non-event based, including price-responsive and reliability DR; (c) consider the role of demand response in avoiding or deferring generation, transmission and distribution infrastructure investment, improving the operational efficiency of existing infrastructure and avoiding high-cost, incremental energy purchases; (d) include an analysis of barriers, and the means to eliminate barriers, to maintaining and increasing levels of demand response resources in the State; and (e) examine the mix of customer end-uses and DR potential within the service territory or sub-regions within the service territory as a factor in determining the DR potential.
 - c. The DR Potential Study must be developed and reviewed through a public, transparent process, which fully includes and considers the input of all stakeholders.
 - d. The DR Potential Study must be completed and reviewed by the Commission and inform Commission adoption of firm goals as soon as reasonably possible.
 - e. The DR Potential Study must include the DR potential associated with best practices for increasing customer participation in event and non-event-based

programs including, but not limited to, rate design, in-home displays, and improved marketing efforts.

- f. The DR Potential Study must include new combinations of DR performance characteristics, including consumer response to price signals, that could meet projected needs in 2020 and beyond, while attracting significant customer participation.
 - g. The DR Potential Study must estimate customer opportunity costs and pricing needs by customer and end-use type and how these costs and pricing needs change as DR adoption increases.
 - h. The DR Potential Study must evaluate opportunities to integrate DR with other distributed energy resources, such as electric vehicles and distributed solar.
- B. *ISSUE AREA #2: VALUATION*^{35/} **AND PROGRAM CATEGORIZATION; AND *ISSUE AREA #4: CAISO MARKET INTEGRATION COSTS*****
- Valuation, Demand Response Program Categorization, and Market Integration Cost Principles.***
- 1. The topics included in the scope of Phase Three of this proceeding by the April 2 ACR and separately identified as Resource Adequacy Concerns, Demand Response Program Categorization (Supply Resource Issues and Load-Modifying Resources Issues), and CAISO Market Integration Costs,^{36/} are, in fact, integrally related and should be addressed and resolved holistically in the manner described in this Settlement Agreement.

^{35/} The terms “value” or “valuation” in this document refers to estimation of the contributions of Demand Response programs to resource adequacy, system reliability or other grid services, as measured, in part, in MW. Other measurement approaches may be considered by the Working Group, described below under Settlement Terms, to the extent that they advance a comprehensive understanding of cost-effectiveness.

^{36/} April 2 ACR, at pp. 4-6.

2. Settlement of these interrelated issues or topic areas is guided by the following core principles and complies with the scope for these issues adopted in the April 2 ACR:
 - a. Both Load-Modifying Resources and Supply Resources provide value, which may include other values in addition to system and local RA credit or reducing RA requirements, that may be identified in the working groups.
 - b. These values will differ depending on the demand response category and on the demand response program or resource characteristics.
 - c. Demand response program valuation can be considered separately for programs that extend beyond 2019.
 - d. It is possible that the CAISO could make operational changes that would enable better use of certain existing demand response programs that are dispatched by the IOUs.
 - e. Certain issues associated with future demand response program characteristics and valuation streams, as well as possible changes to the costs and requirements associated with integrating Supply Resources into the CAISO market, can be better addressed by Settling Party working groups that have specific tasks outlined in the working group charters attached to this Settlement Agreement.
 - f. Output and recommendations from the working groups will inform CPUC, CAISO and CEC procurement and planning processes, and work products.

Resolution of Valuation, Program Categorization, and Integration Cost Issues.

1. All demand response programs will retain current system and local RA valuation based on existing methodology through 2019.
 - a. For SCE's and SDG&E's solicitations resulting from authorizations in the LTPP, and IOU solicitations pursuant to ***DEMAND RESPONSE AUCTION***

MECHANISM, UTILITY ROLES AND FUTURE PROCUREMENT,

subsection C 3.f, below, which may include requests for new DR contracts that extend beyond 2019, the CAISO should verify the system and local RA treatment for Supply Resource contracts, consistent with CPUC RA counting rules. The RA treatment of the Supply Resource contracts approved by the Commission should continue through the life of the contract unless modified in other Commission proceedings.

- b. The Settling Parties agree that the valuation of Load-Modifying Resources after 2019 will be assessed by the working group described in Item 6 below and presented to the Commission for approval. All options are open for how Load-Modifying Resource demand response will be valued after 2019, pending discussions in the working group. The Load-Modifying Resource valuation should be reflected in the program's cost-effectiveness prior to approval of the program.
2. The Settling Parties agree it is only through integration efforts to date and cooperation among entities involved in those efforts that certain barriers/impediments have been identified. To that end, the IOUs will seek to increase cost-effective Supply Resources as barriers to CAISO market integration are overcome, and all Settling Parties will commit to resolving these barriers as cost-effectively and expeditiously as possible, including changes to CAISO processes and IOU program designs, which will be pursued through the Supply Resource Integration Working Group. (See attached Charter for this group.)
3. The Settling Parties agree that they are committed to exploring and implementing improved integration with CAISO operations for event-based Load-Modifying Resources (e.g., enhanced spreadsheet, hard triggers, quasi-market product) and for non-event-based Load-Modifying Resources (e.g., nomograms, elasticity, forecasting,

etc.). This will be done through the Load-Modifying Resource (LMR) Operations Working Group. (See attached Charter.)

4. After the current bridge funding period ends in 2016, and going forward, DR will be designed to provide resources to address pre-determined specific needs. Any such needs will be supported by factual analyses of the services the proposed demand response program can provide and its cost effectiveness in doing so, which may include but are not limited to:
 - a. Reducing system peak or flexible capacity needs;
 - b. Reducing energy costs for customers;
 - c. Reducing distribution costs by avoiding or deferring infrastructure investments or reducing O&M costs;
 - d. Reducing environmental impacts;
 - e. Reducing LSE system and local capacity cost, either by reducing Resource Adequacy requirements adopted in the RA proceeding or by reducing long-term generation capacity needs as reflected in the LTPP; and
 - f. Supporting grid reliability and CAISO operational needs.^{37/}
5. After 2019, only Supply Resources that directly meet reliability or CAISO operational needs (e.g., contingency response, system capacity resources, local capacity resources, flexible capacity resources, operating reserves), will be eligible to receive RA adequacy credit.

^{37/} The Settling Parties note that the terms “reliability” or “grid reliability” as used in this Settlement Agreement may be a subject for briefing in connection with cost allocation only. The presence of these terms in the Settlement Agreement does not create a presumption for or against any party’s position on cost allocation. Signing the Settlement Agreement shall not foreclose positions that a party may wish to take on cost allocation.

6. Valuation of Load-Modifying Resources to reduce RA requirements, reduce long-term generation need and provide other benefits will be addressed by a Load-Modifying Resource (LMR) DR Valuation Working Group that will include Settlement Parties, will incorporate the IEPR-related responsibilities of the Demand Analysis Working Group-Demand Response Subgroup (DAWG-DR subgroup)/Demand Response Measurement and Evaluation Committee (DRMEC)^{38/} and will consider, where possible, actual resource availability and performance in determining resource value. (See attached Charter for LMR DR Valuation Working Group.)
 - a. There is no preconceived decision about how Load-Modifying Resources will be valued after 2019. The LMR DR Valuation Working Group will review a full range of options pertaining to Load-Modifying Resource. (This effort may also identify non-resource adequacy value for Supply Resource as well as for Load-Modifying Resources as a consequence of this process.)
 - b. The purposes of this working group are: (a) to identify mechanisms that could enable Load-Modifying Resource providers to realize all potential demand response values, and (b) to inform quantification of demand response values for the cost-effectiveness protocols and other proceedings such as resource adequacy and long term procurement. The values should be reflected in the cost-effectiveness determination used in the program approval process.
 - c. The DAWG-DR subgroup, in coordination with the DRMEC, will recommend to the Working Group methods for quantifying the impacts of Load-Modifying Resources for purposes of the IEPR demand forecast.
 - d. To the extent that values are identified in the working group, Settling Parties agree that Load-Modifying Resource providers should have an identifiable path to

^{38/} Including staff from the CEC and CPUC.

realize these potential demand response values, such as: (a) avoiding transmission and distribution investments, and (b) reducing the need for flexible capacity.

- e. The Settling Parties agree that the IOUs' costs for any experts who may be hired pursuant to the Charter for Load-Modifying Resource Demand Response (LMR DR) Valuation Working Group will be recorded in existing DR-related balancing accounts to track costs. Pursuant to D.14-01-004 and D.14-05-025, there is no specific budget category for funding these experts. Therefore, the Settling Parties agree that the IOUs would fund their costs for the experts during 2015-2016 from the 2015-2016 DR program authorized budgets as follows:
 - i. the funds are not spent or committed and that the IOUs receive appropriate fund-shifting authority for the bridge-funding period for this purpose;
 - ii. the IOUs can shift funds currently authorized in D.14-05-025, Ordering Paragraphs 10, 15 and 17 without the limitations of the existing fund shifting rules as defined in D.12-04-045 (Ordering Paragraph 4); and
 - iii. the allocation of expert costs among customers for the 2015-2016 bridge period, which is being recorded through existing DR-related balancing accounts, will be subject to briefing and determination by the Commission in this proceeding.
7. A demand response program can be partitioned into a Load-Modifying Resource and a Supply Resource, as long as there is no double counting of participating customers' load reduction. Any partitioning of a demand response program should be done in consultation with the affected third-party DR aggregators, if applicable.
8. IOUs will submit funding and program redesign (or new program) proposals for both Supply Resources and Load-Modifying Resources in their November 2015 applications.

9. A working group will be established whose focus is to reduce CAISO and retail program barriers to participate in CAISO markets as Supply Resources. (See Attached Charter for the Supply Resource Integration Working Group.)
10. The Settling Parties agree to the following policy to apply to existing programs after 2019:

The transition or “grandfathering” period will be over, and all demand response programs will need to meet the resource adequacy rules in existence in 2020 in order to either reduce the resource adequacy requirement as a Load-Modifying Resource or to count toward meeting the resource adequacy requirement as a Supply Resource, consistent with Item 1 above.
11. The Settling Parties agree that the Commission should determine whether the IOUs are increasing Supply Resources and Load-Modifying Resources at a reasonable pace by using the following tools and processes:
 - a. The reports sent to the CPUC to comply with OP 4 of D.14-05-025.
 - b. Review annual resource adequacy requirements, after normalizing exogenous factors, to see if resource adequacy requirements are decreasing over time, compared to what they otherwise would be, due to load modifying effects of DR. Documents that may be also reviewed include studies in long-term procurement planning and transmission planning proceedings, and distribution planning studies.
 - c. A Preferred Resources Monitoring Report will be created as a tool that may be used to track the development of DR resources and ensure that DR intended to meet long-term reliability needs is showing up when and where it is needed.^{39/}

^{39/} Currently the CAISO, CPUC and CEC are involved in jointly monitoring resource development in southern California related to the San Onofre Nuclear Generating Station (SONGS) early retirement. The monitoring approaches created for the SONGS context may be useful in designing a newly created Preferred Resources Monitoring Report that will include all preferred resource development in the CAISO balancing authority area. It would be developed as part of the joint agency monitoring activities and will not be limited to southern California as it is currently structured. Such a report is needed for “off-ramp decisions,” i.e., to enable

Another tool is the annual reporting and possible curing process described in Issue #1 Goals settlement terms in which the IOUs will report how they are progressing towards their goals and providing explanations if goals are not met.

- d. Other appropriate, relevant sources of information may be used.
 - e. A process will be required for identifying and addressing how goals can be met, if they are not being met.
12. To use a resource for local reliability, local capacity and integration into the market, a Supply Resource may qualify for local resource adequacy as a Reliability Demand Response Resource (RDRR) in which there would be a contingency trigger that would allow that resource to show up in the CAISO real-time market at a predetermined price. This local resource adequacy resource will not count toward the system resource adequacy cap on reliability resources adopted in D.10-06-034. The implementation provisions for this option and any limit on the amount of contingency local resource adequacy will be established through a CAISO stakeholder process.

C. *ISSUE AREA #3: DEMAND RESPONSE AUCTION MECHANISM, UTILITY ROLES AND FUTURE PROCUREMENT*

- 1. Parties agree to work together and with CPUC staff to design and implement a DRAM Pilot program during 2015-2016 to test: (a) the feasibility of procuring Supply Resources for Resource Adequacy (RA) with third party direct participation in the CAISO markets through an auction mechanism, and (b) the ability of winning bidders to integrate their provision of DR into the CAISO market. This DRAM Pilot will not set precedent for future procurement of Supply Resources.
- 2. Parties agree to initiate a process as soon as reasonably possible (but no later than December 2014) to develop the rules governing a DRAM Pilot and to seek CPUC

development of a fall back to a needed transmission upgrade or alternative resource type to be triggered if the DR is not developing or performing as intended.

approval of an initial auction to be held in summer of 2015 for delivery in 2016. The DRAM Pilot design, requirements, protocols, standard pro forma contracts and non-binding, cost estimates will be submitted in an advice letter for Commission review and approval prior to the initial auction.^{40/} The Parties intend to commence the development of the DRAM Pilot design, requirements, protocol, and standard pro forma contract in workshops prior to the Commission decision on this Settlement in order to achieve the milestones in the attached draft schedule. Authorization to begin the DRAM Pilot design, protocol and standard contracts prior to a Commission decision will be requested from the presiding administrative law judge, through a Motion for an appropriate ruling.^{41/}

3. Development of the details of the DRAM Pilot must incorporate, at minimum, the following conditions:
 - a. Specific success metrics to inform the Commission of the efficacy of a DRAM and its long-term potential for procurement of Supply Resources.
 - b. Consistency with Electric Rule 24/32 and its implementation timelines.
 - c. IOUs, as buyers in the auction, will not provide bids in the Pilot. IOUs will evaluate and select bids using their respective valuation processes, and consider the costs of other procurement of demand response in assessing reasonableness. Awards will be paid as-bid prices during the Pilot. Independent evaluators will be retained to ensure the process is conducted in a reasonable and neutral manner.
 - d. Bidders will be responsible for meeting all applicable RA requirements and for any financial liabilities that result from participation in the wholesale market.

^{40/} These non-binding cost estimates will assume procurement at the target level based on the best information that is available at the time of filing. If the volume of cost-effective bids exceeds the target, costs may exceed the cost estimate.

^{41/} The Motion for Adoption of the Settlement Agreement also contains a request for a ruling authorizing the IOUs to convene a workshop to address the DRAM Pilot related issues as soon as possible.

- e. Two auctions will be held over the DRAM Pilot period of 2015-2016. A minimum target of 22 MW to be procured in both the initial auction and the second auction held within the Pilot period is to be allocated among the IOUs as follows: 10 MW for PG&E, 10 MW for SCE and 2 MW for SDG&E. As part of the design of the DRAM Pilot, Parties will consider whether and how an IOU's progress towards its targets may be apportioned between the two auctions, and may revise the allocation between an individual IOU's two auctions. If a utility's DRAM contract(s) from the first auction includes MW commitments after 2016, the MWs from the first auction that continue after 2016 will count towards that utility's MW minimum for the second auction.
- f. The IOUs will have the option to conduct non-DRAM RFOs beginning in 2015 for contracts to begin in 2017 and beyond for competitive procurement of Supply Resource and Load-Modifying Resource products that are not being procured in the DRAM (i.e. the RFOs will seek products that have additional features beyond "RA tags" as described in 3.g. below). SDG&E reserves the right to extend the A/C Cycling Summer Saver program. Nothing in this agreement restricts SCE's ability to procure DR resources to meet local reliability needs pursuant to CPUC authorizations in the 2012 long term procurement plan proceeding or as part of SCE's preferred resources pilot. IOUs will follow established CPUC procedures to monitor and review the RFOs, which may include the PRG or CAM review group.
- g. The DRAM pilot is only to procure RA value only products (i.e. RA Tags).
- h. IOUs will not act as the Scheduling Coordinator (SC) for the Pilot but will provide optional SC and related services to winners of the DRAM Pilot via a third party.
- i. Consistency with procurement processes in other CPUC proceedings and CAISO initiatives.

- j. The Settling Parties discussed various methods to encourage participation in the DRAM Pilot and the potential interaction of the IOU solicitations for Supply Resources with the DRAM Pilot but did not come to agreement. Parties agreed that the narrowly scoped additional question of whether the DRAM should be a preferred means of procuring Supply DR and if so, with respect to encouraging participation in the DRAM Pilot, the potential interaction of IOU solicitations for Supply Resources with the DRAM Pilot with respect to encouraging participation in the DRAM Pilot and possible limitations on the IOUs' solicitations for Supply Resources, will be briefed and that request is included in the Motion for Approval of this Settlement Agreement.
4. The Settling Parties agree to two auctions in the DRAM Pilot as described below and subject to further development in the workshop or working group process established in this Settlement Agreement:
 - a. An initial auction for system RA capacity (i.e. "System RA Tags") only targeted for summer 2015 for 2016 delivery and with results incorporated into the IOUs' monthly RA reports for 2016; parties agree to consider whether this initial auction for System RA Tags may include a longer term (i.e., include 2017-2019 delivery in addition to the 2016 delivery) during the design phase of the DRAM Pilot, contingent on funding approval for the 2017-2019 period.
 - b. A second auction held in early 2016 for system, local and flexible RA products (i.e. system, local and flexible RA tags) with results incorporated into the IOUs' annual RA compliance report to be filed in October 2016 for 2017. Contracts for this second auction may extend through 2019.
 - c. The Settling Parties acknowledge and agree that DRAM and wholesale market participation may be significantly impacted by: 1) CAISO tariff changes in

response to recent and future Court rulings on FERC Order 745, and 2) CAISO requirements for RA product eligibility.

- d. A Draft Schedule for implementation of an initial auction and a second auction are attached to this Settlement Agreement.
5. Among other outcomes, a DRAM Pilot should result in assessing the feasibility of using an auction process to create opportunities for and competition among DR providers to provide cost-effective Supply Resources to meet Loading Order goals.
 6. For purposes of evaluating the DRAM Pilot:
 - a) IOUs, in collaboration with other stakeholders, will prepare a report describing the “lessons learned” from the auction process.
 - b) Subject to appropriate confidentiality protections, the report will include information set forth in a way that protects any confidentiality, trade secret or sensitive information privileges that are applicable, on an aggregated basis if necessary, concerning the capacity bids and selected bids in the DRAM, and any incremental costs and benefits to the IOU from using the DRAM.
 - c) Subject to appropriate confidentiality protections, access to information on bids into the CAISO market, CAISO awards, and resource performance may be needed to evaluate integration of the DRAM products into the CAISO market, load impact evaluation, and possibly contract administration. Procedures to provide access to this information, perhaps in aggregated form, will be part of the DRAM design.
 7. The Settling Parties agree that the IOUs’ costs for the DRAM Pilot, including without limitation, the costs of the auction, the payment of incentives, and the costs of providing optional SC and related services to the winners of the DRAM Pilot via a third party, will be recorded in existing DR-related balancing accounts to track costs. Under D.14-01-004 and D.14-05-025, there is no specific budget category that could completely fund 2015-16 DRAM expenses. Therefore the Settling Parties agree that

the IOUs would fund their costs for the DRAM pilot during 2015 and 2016 from the 2015-2016 DR programs authorized budgets, as follows:

- a. the funds are not spent or committed and that the IOUs receive appropriate fund-shifting authority for the bridge-funding period for this purpose;
 - b. the IOUs can shift funds currently authorized in D.14-05-025, Ordering Paragraphs 10, 15 and 17, without the limitations of the existing fund shifting rules as defined in D.12-04-045 (Ordering Paragraph 4), to fund these costs;
 - c. if sufficient bridge funding is not available to fund incentives for approved DRAM Pilot contracts in 2016, after the winners of the DRAM auction are determined, the IOUs would file an advice letter to fund those incentives; and
 - d. the allocation of costs among customers of the 2015-2016 DRAM Pilot-related amounts recorded through existing DR-related balancing accounts shall be subject to briefing and determination by the Commission in this proceeding. The allocation of the DRAM-related amounts in 2017-2019 among customers shall be pursuant to the Commission's decision on cost allocation in this proceeding.
8. In order to implement subsection 7 above, the Settling Parties request in the Motion for Adoption of Settlement Agreement submitted concurrently with this Settlement Agreement that the Commission's decision on the Settlement Agreement determine that the DRAM Pilot be included among the 2015-2016 DR programs to be funded by the budgets authorized in Ordering Paragraphs 10, 15 and 17 of D.14-05-025, which adopted 2015-2016 budgets respectively for PG&E in Attachment 2 , for SDG&E in Attachment 3 and for SCE in Attachment 4 to D.14-05-025. The Settling Parties also request in the Motion for the Adoption of the Settlement Agreement that the Commission decision on the Settlement Agreement authorize the IOUs to shift funds from existing DR categories to cover the costs of the DRAM Pilot costs identified in

subsection 7 above, without the limitations of the existing fund-shifting rules contained in D.12-04-045, Ordering Paragraph 4.

D. ISSUE AREA #4: BUDGET CYCLE

1. The Settling Parties request that the CPUC establish one more three-year budget cycle (2017 2019).
 - a. Each IOU's respective demand response portfolio will contain an explanation of an identified need for each program, and must meet CPUC cost-effectiveness requirements in accordance with CPUC guidelines.
 - b. The Settling Parties request that the CPUC conduct one (1) mid-cycle review of the IOU DR program activities, via a public workshop, which will allow for parties to provide input on potential mid-cycle revisions to the IOUs' tariffed DR programs to enhance DR program participation and performance. The IOUs may request revisions to the IOUs' tariffed DR programs, taking into account parties' input.
2. To determine whether an extended budget cycle is appropriate, the Settling Parties agree to initiate a process by April 1, 2015 to develop the rules governing a potential extended DR budget cycle by December 31, 2015 for CPUC approval by March 31, 2016.
3. Development of the details of an extended budget cycle must be coordinated with, at minimum, the following issues:
 - a. Implementation of Electric Rule 24/32.
 - b. CPUC decisions issued on IOU applications pursuant to Public Utilities Code Section 769 (IOU Distribution Plans which are due in July 2015).
 - c. Key CAISO stakeholder processes.
 - d. Key processes in other CPUC proceedings.

- e. Implementation of other key issues in this Settlement.
 - f. Developments in the Energy Efficiency proceeding concerning budget cycles.
4. Among other details, the process of developing the details of an extended DR budget cycle should result in: (1) a determination of an extended budget cycle length and; (2) how often reviews should occur and the appropriate level of scrutiny.

III. CONDITIONS

This Settlement Agreement resolves the issues raised by the Settling Parties for Phase Three in R.13-09-011, subject to the conditions set forth below:

1. This Settlement Agreement embodies the entire understanding and agreement of the Settling Parties with respect to the matters described, and it supersedes prior oral or written agreements, principles, negotiations, statements, representations, or understandings among the Settling Parties with respect to those matters.
2. This Settlement Agreement represents a negotiated compromise among the Settling Parties' respective litigation positions on the matters described, and the Settling Parties have assented to the terms of the Settlement Agreement to arrive at the agreement embodied herein. Nothing in the Settlement Agreement should be considered an admission of, acceptance of, agreement to, or endorsement of any disputed fact, principle, or position previously presented by any of the Settling Parties on these matters in this proceeding.
3. This Settlement Agreement does not constitute and should not be used as a precedent regarding any principle or issue in this proceeding or in any future proceeding.
4. This Settlement Agreement is reasonable in light of the testimony submitted, consistent with the law, and in the public interest.

5. The language in all provisions of this Settlement Agreement shall be construed according to its fair meaning and not for or against any Settling Party because that Settling Party or its counsel or advocate drafted the provision.
6. The Settlement Agreement addresses all the issues in Phase Three of the April 2, 2014 *Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two and Providing Guidance for Testimony and Hearings*, (April 2 ACR).
7. The Settlement Agreement provides for briefing two Phase Two issues, cost allocation and BUGS, and also a narrowly scoped additional issue, whether the DRAM should be a preferred means of procuring Supply DR and if so, with respect to encouraging participation in the DRAM Pilot, the potential interaction of IOU solicitations for Supply Resources with the DRAM Pilot with respect to encouraging participation in the DRAM Pilot and possible limitations on the IOUs solicitations for Supply Resources.
8. This Settlement Agreement may be amended or changed only by a written agreement signed by the Settling Parties.
9. The Settling Parties shall jointly request Commission approval of this Settlement Agreement and shall actively support its prompt approval. Active support shall include written and/or oral testimony (if testimony is required), briefing (if briefing is required), comments and reply comments on the proposed decision.^{42/}

^{42/} Any oral and written testimony that the Commission might require may be prepared and submitted jointly among parties with similar interests.

10. If a Commission Decision regarding this Settlement Agreement contains any material change to the Settlement Agreement, the Settlement Agreement shall be null and void, unless all of the Settling Parties agree in writing to such changes.
11. The Settlement Agreement shall be interpreted and treated as a unified, integrated agreement. In the event the Commission rejects or modifies this Settlement Agreement, the Settling Parties reserve their rights under Rule 12 of the CPUC's Rules of Practice and Procedure, and the Settlement Agreement should not be admitted into evidence in this or any other proceeding.
12. The Settling Parties (a) have read this Settlement Agreement and fully understand all of its terms; (b) agree that they have executed this Settlement Agreement without coercion or duress of any kind; and (c) agree that they understand any rights they may have and sign this Settlement Agreement with full knowledge of any such rights.
13. The Settling Parties further represent that they have had the opportunity to thoroughly discuss all aspects of this Settlement Agreement with their respective legal counsel.
14. This Settlement Agreement may be executed in counterparts, each of which shall be deemed an original.
15. The details of the Settlement Agreement on Issue Areas 1, 2, 3, 4, and 5 are set forth herein. Two other issue areas in this proceeding in Phase Two, Cost Allocation and fossil-fueled back-up generation (BUGs), have not been settled, and the Settling Parties have agreed to brief these two issues and the narrowly scoped additional issue whether the DRAM should be a preferred means of procuring Supply DR and if so, with respect to encouraging participation in the DRAM Pilot, the potential interaction of IOU solicitations for Supply Resources with the DRAM Pilot with respect to encouraging participation in the DRAM Pilot and possible limitations on IOU solicitation for Supply Resources, for decision by the Commission.

16. The undersigned represent that they are authorized to sign on behalf of the Party represented.

IV. REGULATORY APPROVAL

The Settling Parties agree to use their best efforts to obtain Commission approval of this Settlement Agreement. To that end, the Settling Parties agree to jointly request that the Commission: (1) approve this Settlement Agreement without material change; and (2) find that this Settlement Agreement is reasonable in light of the whole record, is consistent with the law, and is in the public interest.

V. PERFORMANCE

The Settling Parties agree to perform diligently and in good faith all actions required hereunder, including, but not limited to, the execution of any other documents and the taking of any actions reasonably required to effectuate the Terms and Conditions of this Settlement Agreement, as well as the preparation of exhibits for, and presentation of witnesses at, any hearings required to obtain the Commission's approval and adoption of the Settlement Agreement.^{43/} The Settling Parties will use best efforts to ensure that this Settlement Agreement is approved by the Commission as soon as possible.

^{43/} Whereas, the Settling Parties collectively support the commitments to future work described in the Terms and Conditions herein, they recognize that individual Settling Parties may not have the interest, ability, or resources to participate in each and every activity described

CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

THE UTILITY REFORM NETWORK

By: /s/Keith Casey
 KEITH CASEY

By: /s/Marcel Hawiger
 MARCEL HAWIGER

Title: Vice President, Market and Infrastructure
Development
Date: July 28, 2014

Title: Attorney
Date: August 1, 2014

ALLIANCE FOR RETAIL ENERGY
MARKETS/DIRECT ACCESS CUSTOMER
COALITION

ENERNOC, INC.,
A Delaware Corporation

By: /s/Daniel W. Douglass
 DANIEL W. DOUGLASS

By: /s/Matthew J. Cushing
 MATTHEW J. CUSHING

Title: Counsel
Date: August 1, 2014

Title: General Counsel & Vice President
Date: August 1, 2014

COMVERGE, INC.

JOHNSON CONTROLS, INC.

By: /s/Frank Lacy
 FRANK LACEY

By: /s/Jennifer Chamberlin
 JENNIFER A CHAMBERLIN

Title: Vice President of Regulatory & Market
Strategy
Date: August 4, 2014

Title: Dir. Reg. Affairs – Int. Demand Resources
Date: July 31, 2014

OLIVINE, INC.

ENVIRONMENTAL DEFENSE FUND

By: /s/Elizabeth Reid
ELIZABETH REID

By: /s/Michael Panfil
MICHAEL PANFIL

Title: Chief Executive Officer
Date: August 2, 2014

Title: Attorney
Date: August 4, 2014

MARIN CLEAN ENERGY

ENERGYHUB/ALARM.COM

By: /s/Elizabeth Kelly
ELIZABETH KELLY

By: /s/Seth Frader-Thomason
SETH FRADER-THOMPSON

Title: Legal Director
Date: August 4, 2014

Title: President, EnergyHub
Date: July 30, 2014

CLEAN COALITION

SIERRA CLUB

By: /s/Stephanie Wang
STEPHANIE WANG

By: /s/Matthew Vespa
MATTHEW VESPA

Title: Policy Director
Date: August 1, 2014

Title: Senior Attorney, Environmental Law
Program
Date: August 1, 2014

**ATTACHMENT A
TO SETTLEMENT AGREEMENT**

**CHARTER FOR SUPPLY RESOURCE DEMAND RESPONSE
INTEGRATION WORKING GROUP**

Charter for
Supply Resource Demand Response Integration Working Group

July 25, 2014

1. Purpose of Working Group:

The purpose of the Working Group is twofold: 1) to identify areas where requirements for integration of supply resources demand response into CAISO markets are adding significant cost and complexity, to determine whether these requirements can be simplified or changed without creating operational problems, to prioritize these possible changes, and to resolve them; and 2) to identify program modifications and operational techniques to make demand response programs more suitable and successful as supply resources. This is not a policy group but a technical group to discuss IT, systems, and operational matters.

2. Products:

- a. The first Working Group product should be a list of areas for change, priorities, proposed solutions (both from a CAISO perspective and from an IOU program redesign perspective) and a time-line for resolution.
- b. The output of the Working Group will be input into IOU demand response applications, CAISO stakeholder processes, resource adequacy proceedings, long term procurement proceedings, possible review of Rule 24/32 requirements adopted by the CPUC and other possible proceedings as appropriate.

3. Structure:

The Working Group will consist of members of the staffs of the investor-owned utilities (IOUs), demand response providers (DRPs), CAISO, and CPUC, as well as other load-serving entities (LSEs), customer representatives, and public interest groups, if interested. All members should be conversant in the technical aspects of integration of demand response into CAISO markets, Rules 24/32, and resource adequacy requirements.

4. Governance (process and principles):

Process: The group should focus on: 1) technical solutions and processes that may decrease the cost and complexity of integration of DR into the CAISO markets, and 2) program design changes or technology solutions that reduce the complexity and cost of integration. While the CAISO is the ultimate entity to approve changes to its requirements, the group should collaborate to find mutually-acceptable solutions.

5. Schedule:

The Working Group should begin meeting by September 2014, with the intention of developing a list of proposed changes, priorities, and a time-line by mid-year 2015, at

which time the Working Group will have no additional tasks unless further agreed by the Working Group members based on experience in 2015. While this time frame precedes a decision in Phases 2 and 3 of R. 13-09-011, discussion to date shows consensus on a number of issues. Since solutions will take time, in order to allow increased integration of DR into CAISO markets sooner rather than later, the group should start working before any December 2014 decision.

6. How results will be used:

The results should be used to inform future CAISO stakeholder processes addressing demand response integration issues and possibly to inform a future review of possible changes to Rule 24/32 or RA requirements. Proposed demand response program design changes will inform the IOUs' 2017-2019 demand response applications.

7. Prioritization:

The Working Group will establish its own priorities for reviewing the areas for possible change already identified and developing new ones. Based on work to date, the following areas are good initial candidates for possible change and additional items will be considered by the group. To the extent that some issues involve policy considerations or policy changes, the Working Group will identify and prioritize but not address such issues:

- a. automating CAISO resource registration and updates (includes bulk-loading registrations and functionality to update existing PDRs)
- b. reconsidering the requirement that each resource must contain customers from a unique LSE
- c. reconsidering of the requirement for LSE approval for utility and non-utility DRPs to bid load of customers into CAISO markets
- d. business systems automation for verifying that no load participates in more than one resource
- e. creating functionality for changes to RDRR locations during the year, at least on a monthly basis, and proposals that qualifying capacity changes of RDRR be accounted for in RA showings per rules established in CPUC RA proceeding for CPUC-jurisdictional LSEs
- f. creating of CAISO stakeholder process to consider adding functionality for constrained or discrete dispatch option for marginal dispatch of DR
- g. automating support of baseline and performance requirements, e.g. for partial dispatch of PDR over monthly use limitations
- h. implementation of statistical sampling rules
- i. creating CAISO stakeholder process to address near real-time data requirements, including exploration of use of AMI local network, KYZ pulse output, and 3rd party systems; may involve review of 1-minute requirement
- j. program dispatch automation

- k. enhanced forecasting techniques and methodologies
- l. tailored program offerings (one size does not fit all) and incentive structures
- m. Consider way to reduce constraints imposed by the 100 kW minimum resource requirement by sub-LAP and LSE. Explore alternatives such as combining LSEs in a single registration or combining sub-LAPs if and where operationally acceptable. Also consider how to better integrate LCAs and SubLAPs.

**ATTACHMENT B
TO SETTLEMENT AGREEMENT**

**CHARTER FOR LOAD MODIFYING RESOURCE DEMAND RESPONSE
VALUATION WORKING GROUP**

Charter for
Load Modifying Resource Demand Response (LMR DR) Valuation Working Group
July 25, 2014

8. Purpose of Working Group:

- a. The Working Group will recommend how LMR DR should be valued after 2019.
- b. The Working Group will determine how LMR DR will be incorporated into the California Energy Commission (CEC) IEPR forecasts, both for existing LMR DR programs and for LMR DR programs after 2019. The CEC IEPR forecast will be used to inform the CPUC's resource adequacy, the long term procurement proceeding and the CAISO's transmission planning process.
- c. Resource adequacy value is a critical issue identified by the CPUC for this phase of R.13-09-011 (See April 2 ACR). The Working Group will also recommend how LMR DR will be valued for setting and informing resource adequacy proceedings, long term planning proceedings, demand response cost effectiveness determination and future distribution planning needs.
- d. The Working Group will look at both event based LMR DR and non-event based LMR DR
- e. The Working Group will identify other values that LMR DR may provide and recommend to the CPUC, CEC and CAISO mechanisms related to how that value should be realized by resource owners.
- f. The Working Group will seek to identify mechanisms that could enable LMR DR resource owners and ratepayers to realize all potential DR values.
- g. The working group will seek to inform quantification of demand response values for the cost-effectiveness protocols and other proceedings such as resource adequacy. (These values may apply to supply-side demand response as well)

9. Products:

- a. The output of Working Group will feed processes and procedures that are incorporated in (i) the CEC IEPR, where the output affects components of the IEPR demand forecast, and (ii) the appropriate CPUC proceedings where other aspects of demand response valuation are relevant.
- b. The Working Group will recommend how LMR DR should be properly valued in the resource adequacy proceedings, the long term procurement proceedings, and the transmission planning process and as part of future distribution planning needs.

- c. The Working Group will recommend existing mechanisms or propose new mechanisms to enable LMR DR resource owners to realize each potential demand response value stream.
- d. The Working Group will develop a plan for coordinating the implementation of each recommended mechanism for realizing DR values through existing and proposed CPUC, CEC and CAISO dockets and initiatives.
- e. The Working Group recommendations should inform the R. 13-09-011 Phase 4 demand response road map.

10. Structure:

- a. The Working Group will be public and composed of the members of the Settling Parties from R. 13-09-011 Phase 3, as well as key expert groups such as the DAWG and DRMEC.
- b. The ISO has suggested the DAWG – specifically the newly forming DAWG- DR pup - as a core technical team to address methods for incorporating the impacts of LMR DR into the IEPR forecast. To this end the DAWG-DR pup will draw on its experience with incorporating energy efficiency savings into the IEPR forecast, and will coordinate with the DRMEC. The DAWG’s existing experience and connection with the IEPR will be beneficial.
- c. DRMEC is also an expert group that the Working Group can utilize to provide technical expertise and experience on how demand response impacts are determined.
- d. The Working Group should also hire outside third party experts (funding source TBD) as needed to help inform the work of the group.

11. Governance (process and principles):

- a. Process
 - Generally works on consensus basis
 - Should strive to have essential needs met of all parties (no group is “extra special”).
 - Develop a report with recommendations detailing final recommendations and each party’s position that may be presented in a public workshop
 - The report should be used to build the CPUC’s record along with public comments
 - Include all interested stakeholders
- b. Principles:

- Do not over- or under-value demand response due to bifurcation (no intention to diminish value of DR in either category per D. 14-03-026)
- Follow the Loading Order
- Working Group recommendations will be based on evidence and facts, and will use outside experts if needed.
- Valuation should be reflected in the cost effectiveness determination before programs are approved.
- Demand response values should be made fully transparent, with mechanisms to harvest that value made available to ratepayers, third parties and IOUs. DR costs should also be transparent but will be addressed in cost-effectiveness analysis rather than in this Working Group.

12. Schedule:

- a. Potential members of the proposed Working Group will begin to form and coordinate with DAWG and DRMEC before the CPUC decision so that it can have a fast start. This work should begin after the Settlement has been filed. Because the DAWG-DR pup's tasks must feed into the CEC's 2015 IEPR process in a timely manner, its portion of the work will likely have to begin prior to the CPUC decision.
- b. Meet officially within 10 working days of CPUC decision authorizing the Working Group. This is currently expected to be early January 2015.
- c. The recommendations should be completed by May 1, 2015 so that they can be factored into the timeline established by the Joint Agency Steering Committee (JASC) and this proceeding and other proceedings:
 - Phase Four of this proceeding, which will develop a DR road map
 - The IOU DR Applications to be filed in November 2015
 - Submitted into the CPUC resource adequacy proceeding that will make a Decision in June 2016 for the 2017 RA rules
 - Go into 2015 IEPR
 - Go into the 2016 long term procurement proceeding

13. Prioritization:

A list of items to address for LMR DR valuation will be one of the first tasks the Working Group will prioritize.

**ATTACHMENT C
TO SETTLEMENT AGREEMENT**

**CHARTER FOR LOAD MODIFYING RESOURCE DEMAND
RESPONSE OPERATIONS WORKING GROUP**

Charter for
Load Modifying Resource Demand Response (LMR DR) Operations Working Group
July 25, 2014

14. Purpose of Working Group:

Identify and develop processes that allow the CAISO to better incorporate LMR DR into its operations so that LMR DRs value is fully captured

15. Products:

The output of this working group would be a series of proposals for 1) providing greater operational visibility to the CAISO of LSE use of LMR DR, 2) providing CAISO better tools to forecast the impact of LSE-dispatched event or non-event based LM DR on CAISO loads in the day-ahead and real-time markets, and 3) improving the ability of the CAISO to call LMR DR when needed

16. Structure:

This working group would consist of members of the staffs of IOUs, the CAISO, the CPUC, and of other LSEs, DRPs, consumer representatives, and public interest groups where of interest. This is not a policy group but a technical group to discuss IT, systems, procedures and operational matters. All members should be conversant in the technical aspects of DR program design and CAISO markets.

17. Governance (process and principles):

Process: The group should focus on 1) technical solutions and processes that increase the ability of CAISO operators to be aware of LSE dispatch of LMR DR programs and to reflect the use of these programs, whether event or non-event based, in its day-ahead and real-time forecasting, and 2) improving the processes for the CAISO to call LMR DR if needed for reliability purposes. While the CAISO is the ultimate entity to adopt any changes to its operations that may result from this greater visibility and information, the group should collaborate to find mutually-acceptable solutions. Outside experts may be retained if needed (funding source TBD).

Principles:

- Follow the Loading Order
- Do not diminish DR value per D. 14-03-026, as long as DR provides similar services and benefits
- Consider whether and how DR can better contribute to price formation in CAISO markets if it is not bid in as SR DR

18. Schedule:

The Working Group should begin meeting by September 2014, with the intention of developing a list of proposed changes, priorities, and a time-line in September if possible. The list can be updated going forward based on experiences in 2015, if necessary. While this time frame precedes a decision in Phases 2 and 3 of R. 13-09-011, discussion to date shows levels of agreement on a number of issues. Since solutions will take time, in order to allow increased visibility of LMR DR to the CAISO, including for forecasting purposes, sooner rather than later, the group should start working before any December 2014 decision.

19. How results will be used:

The results should be used to inform future CAISO stakeholder processes addressing incorporation of LMR DR information into its load forecasting and operations.

20. Prioritization:

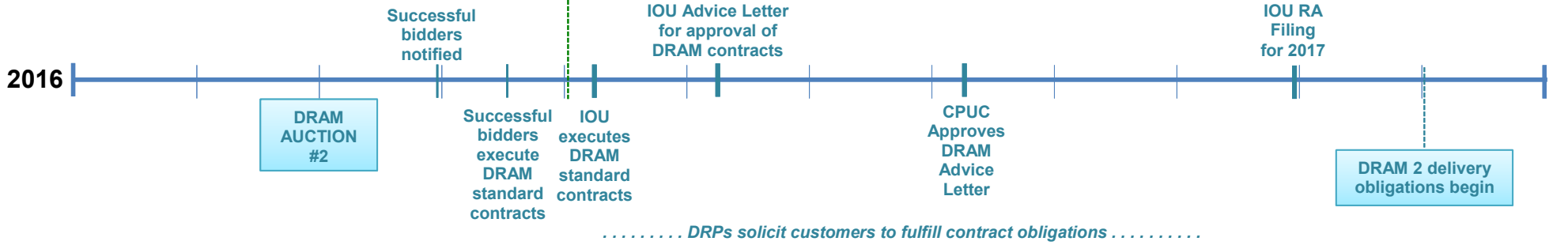
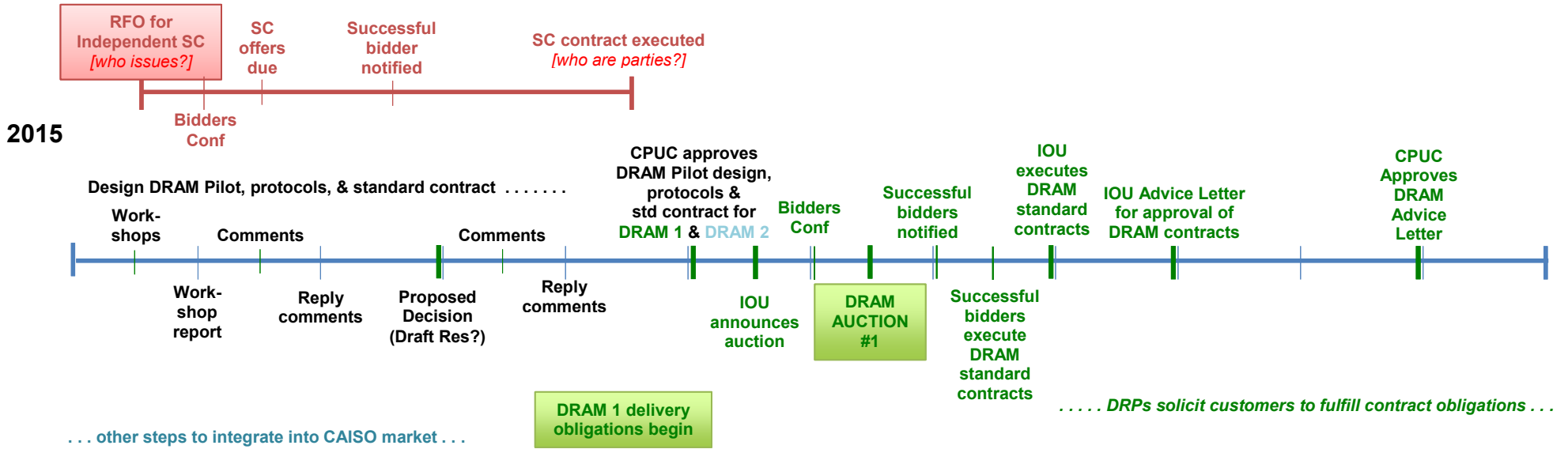
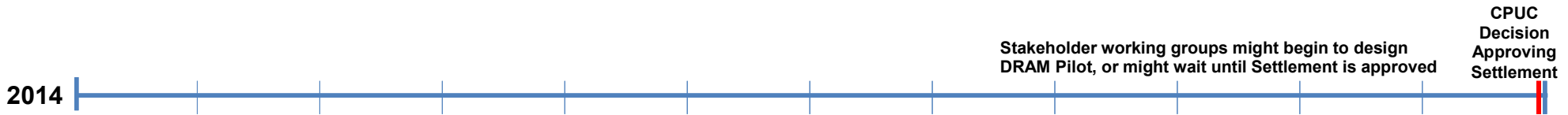
- a. The Working Group may explore the following ideas:
 - Have “automated” system to get the Daily DR Report into the CAISO system
 - Have “hard” (must dispatch) triggers with specific amounts of MW that can be used in CAISO forecasts
 - “Bid” LMR DR into CAISO market but with no settlement or registration requirement in order to provide the CAISO with visibility to these resources and their dispatch by LSEs; consider other means of providing visibility as well
 - Include Dispatchable LMR in CAISO market via Load bid
 - Determine whether and how LSE dispatch of LM DR could be reflected in CAISO forecasting
 - Determine whether some form of low-cost telemetry can be used to provide visibility to the CAISO of dispatched LMR DR
 - Consider whether LMR DR can affect requirements for ancillary services
 - Other ideas were included in the testimony of Dr. Papalexopoulos and PG&E December 13, 2013 comments

**ATTACHMENT D
TO SETTLEMENT AGREEMENT**

DRAFT SCHEDULE TO COMPLETE TWO DRAM AUCTIONS

DRAFT SCHEDULE TO COMPLETE TWO DRAM AUCTIONS, 2015 (System only) & 2016 (System, Local & Flexible)

JAN FEB MAR APR MAY JUN JUL AUG SEPT OCT NOV DEC



ADDITIONAL DRAM AUCTIONS?

**ATTACHMENT B
TO MOTION**

COMPARISON EXHIBIT

Comparison Exhibit - Original Party Positions and Settlement Outcome for Issues from April 2, 2014 Ruling and Revised Scoping Memo

Party	Goals	Resource Adequacy	Integration Costs	Supply Resources/DR Auction Mechanism	Load Modifying Resources	Application Process	Cost Allocation
PG&E	> goals should be not be quantitative > CPUC should implement plan to maximize DR MWs	> Supply Resources (SR) and Load Modifying Resources (LMR) should receive comparable RA value	> Integration costs likely to be significant > A transition period is needed to gain experience and reduce costs	> SR is DR program that provides a product CAISO directly procures > No current PG&E programs have SR characteristics > PG&E can offer 10-20MW of DR as SR > DRAM is complex and requires further examination	> LMR are programs that do not have SR characteristics > LMR provide value similar to SR > LMR can work in CAISO wholesale market	> 10 year rolling program cycle with annual adjustments	
SCE	> Any goals for DR should be determined by first identifying system needs, then understanding how a balanced portfolio of resources can meet those needs, and finally defining what role DR can play among that portfolio of resources	> primary concern related to RA, specific to the bifurcation framework, is that dispatchable DR programs that currently receive RA value should continue to receive RA value, regardless of how these programs are categorized	> defers to June 2nd DR Direct Participation (Rule 24) cost recovery application	> Utilities and third parties can both be effective providers of Supply Resource DR while Load Modifying Resource DR relies on utility rates and a utility-centric model > supports competitive procurement of preferred resources but recommends that the ED's DRAM Proposal be deferred until at least 2017 to align with the next DR funding cycle and to allow time for lessons learned from other efforts to be implemented	> Utilities and third parties can both be effective providers of Supply Resource DR while Load Modifying Resource DR relies on utility rates and a utility-centric model;	> SCE supports a longer program budget application process, with the specific cycle length and process details to be determined after other policy issues in the Revised Scoping Memo are resolved	
SDG&E	> Specified goals not needed > CPUC should approve and encourage all cost-effective DR programs > Current rate design discourages economically efficient DR > The most economically efficient form of DR is DR in response to accurate price signals	> Not clear how LMR will provide RA > SR will bear additional costs to directly bid into the CAISO markets and will also be exposed to any non-availability charges and underperformance costs. > It is expected that LMR's impact on RA would be reduced	> Provides cost estimates to integrate DR programs	> SR defined as PDR or RDRR > CBP and BIP are SRs > Recommends process evaluation to improve DR program response > The proposed DRAM should be rejected	> LMR are programs that do not have SR characteristics > LMR provide value similar to SR > LMR can work in CAISO wholesale market	> Longer program cycles (up to 10 years) would provide benefits	
CAISO	> In the context of the loading order, the Commission should establish annual supply-side demand response goals tied to the Commission's long-term procurement authorizations	> Supply side demand response should count as resource adequacy capacity, load modifying demand response should not count as resource adequacy capacity but can lower resource adequacy requirements.	There are opportunities to reduce cost and complexity related to integrating DR as a supply resource and CAISO is committed to continuing engagement with stakeholders to identify areas for improvement and investigate viable alternative approaches.	> A supply-side resource is a resource that can be scheduled in day-ahead or real-time operation and that a system operator can include in system-wide dispatch when needed, where needed, and for a needed quantity > Emergency and local DR providing RA should be a SR > As the CAISO noted during the recent long term procurement proceeding, the Commission should ensure that adequate tracking processes are in place to monitor the development and effectiveness of supply-side demand resources, particularly in critical areas such as southern California	> Load modifying programs, like critical peak pricing or conservation requests do not normally result in a targeted outcomes > For category-funded load modifying demand response programs that are event-based, the Commission should apply similar, if not identical, performance obligations and non-compliance penalties to utility programs as those applied to third-party demand response providers who operate under the utilities' aggregator managed portfolio programs.		
ORA	> 5% goal is reasonable > goal is to maximize cost-effective DR	> ED adjustments to ex-ante load impacts used in establishing RA capacity are not clearly defined and understood and should not be made in an ad hoc manner > provide additional guidance so the ED's adjustments are done in a transparent manner > there is no well-defined process for determining the amount of conventional generation resources avoided by LMRs > establish a formal process in collaboration with the CEC to determine how load modifying programs are accounted for in the CEC's load forecast	> Reasonableness of integration costs should be judged in terms of the overall cost effectiveness of DR programs > Defers to CAISO on PG&E recommendations to reduce integration costs	> Agrees generally with the bifurcation of programs noted in D.14-03-026 > The CAISO and DR providers should collaborate on finding innovative ways to reduce DR integration costs consistent with the level of visibility of DR resources necessary for operating the grid in a reliable manner. > DRAM concurs with ED target goals; auction should be as-bid with a cost cap of weighted average of bids received. > DRAM: concerned about long term contracts (customer retention); limiting frequency of auctions; clarify emergency program bidding	> Agrees generally with the bifurcation of programs noted in D.14-03-026 > ED should review and direct IOUs to improve load forecasting > There should be no specific goals for LMR impacts	> A longer program cycle would avoid bridge funding > DR aggregators have not shown that they can recruit a customer over a longer term > Cost effectiveness and annual performance still must be evaluated at regular intervals to identify underperforming contracts.	
DACC/AREM				> The Commission does not have jurisdiction to require ESPs to procure through the proposed DR auction mechanism.			Should be decided in this proceeding
Clean Coalition	> proposes a needs-based approach for developing DR goals. The purpose is to set goals that can be readily translated into increased 10 reliance on demand response in procurement plans and transmission plans > recommended framework for setting demand response goals will also reveal how much demand response will be available to meet operational needs						
CLECA	> It is premature to set goals for demand response now; the goals should be informed by the record under development in this track and the experiences of at least this summer	Since all demand response affects resource requirements for Resource Adequacy, the Commission must ensure that all demand response is taken into consideration and affects procurement requirements and levels	> Costs associated with integration into CAISO markets can reduce the cost-effectiveness of supply resource demand response programs, and integration costs imposed on individual customers and the system as a whole must be mitigated to avoid rendering such demand response programs cost-ineffective	> Two criteria should be used to categorize demand response programs as supply resources: first, whether CAISO dispatch is required for the program to provide its intended service; second, whether the integration costs are not so great that they make the program cost-ineffective > There are many threshold questions on the DRAM that need to be worked through before its implementation, even on a preliminary basis > It is not necessary to include reliability DR in the DRAM > The apparent assumption that the federal Net Benefits Test is a substitute for a Commission determination on cost-effectiveness is misguided > Forecasting the impact on the load shape of dynamic pricing and having the CAISO take that impact into account is just as important as expanding dynamic pricing.		> Longer program cycles and program stability are warranted	

EDF	Goals should be driven by creating transparent valuation of all DR benefits, and enabling those to be harvested by utilities, third parties, and ratepayers	RA should be used as an incentive mechanism to induce all types of DR, including those contributing T&D benefits, or an alternative mechanisms, such as comprehensive valuation, should be adopted.		> Auction should include event-based programs (CBP, DBP, BIP, SmartAC, etc) > Longer term contracts and improved forecasting are needed > Significant time needed to develop effective DRAM	LRM should be comprehensively valued, including by time and place. Similarly, more granular (geographic) forecasting is needed to ensure that LMR's contributions are fully reflected in IEP and associated planning proceedings.			
Joint DR Parties	> 5% goal is reasonable starting point; Commission needs to examine reasons why DR resource success is not greater; need to address concerns with wholesale market integration; > Integrate DR in utility resource planning > encourage greater DR participation	> The rules that would apply to DR resources that participate in the wholesale market for RA purposes, and are, therefore, eligible for a capacity payment, have not been settled and may take longer than expected to achieve FERC approval. LMRs should not be valued less than supply-side resources for RA purposes. JDRPs are concerned about the discontinuity in the way DR resources are counted for local resource adequacy purposes but not counted toward meeting a local capacity requirement in the LTPP. JDRPs also wanted to have better alignment between how DR resources are paid and counted for RA purposes. > A must-offer obligation is not an efficient method of dispatching DR > the IOUs should be able to utilize a resource for distribution level needs	> Integration costs are significant and may likely be higher than other markets (PJM and ERCOT)	> Participation of and requirements for DR resources in wholesale markets remains unsettled > There are numerous shortcomings to resolve to create a DRAM. Expectations as to frequency of dispatch of DR resources increasing by virtue of participating in the wholesale market must be tempered due to the reality of use limitations, low market clearing prices, customer opportunity costs, etc. The role of the utility may need to be examined, depending upon the types of services that will be provided.	> LMRs can be either resources that are exposed to rate changes through utilities tariffs or are dispatchable based upon system conditions. > Utilities are likely to be the most significant, if not the exclusive, provider of these services.	> Longer program cycles are desirable		
MCE				> DRAM should not apply to CCAs	> Utility centric DR programs are anti-competitive	> supports longer program cycles		
Sierra Club	> Appropriate to adopt measurable transition goals > 2nd ruling proposed goals (Attach B) are sufficient; PJM goal is 14% > Success in achieving goals depends on removing barriers & integrating with RA & LTPP	> April	> Integration cost barrier may be significant; others can be mitigated	> Concurs with bifurcation of programs in Hynes' > Depending on its implementation, the proposed DRAM may retard, rather than promote, the growth of DR and provides recommendations to improve it > Proposed bid cap may lead to suboptimal results > Transition of Supply Resources to CAISO should be staged gradually	> LMR success depends on clear & correct price signals, customer-friendly tariff designs, & effective utility marketing			
TURN	> strongly concerned that an arbitrary goal linked to procurement requirements could significantly increase costs due to a lack of technical potential or supplier market power if there is insufficient market competition > recommends that the Commission use the proposed price cap (based on a weighted average of bid prices) in conjunction with an exogenous benchmark based on a measure of cost effectiveness			> generally agrees with the preliminary categorization as shown in Table 2 of D-14-03-026, with one caveat concerning permanent load shifting resources > The characteristics of particular Supply Resources are influenced both by customer preferences and the extent of control and communications technology automation > TURN supports DRAM as a vehicle to reduce program costs and increase cost transparency > Require all supply resource demand response to participate in the DRAM starting in 2017 and 2018 > Provide for a specific review and reauthorization of the DRAM after piloting the program for 2016 and 2017 > Additional testimony (Woodruff) details clarifications and modifications required for DRAM	> generally agrees with the preliminary categorization as shown in Table 2 of D-14-03-026, with one caveat concerning permanent load shifting resources > concerned about PLS as a LMR			
Opower	> CPUC should create participation goals > Provides recommendations to improve marketing of DR programs							
Energy Hub	> Expand participation of DR in residential market		> agree with PG&E's list of actions that will likely reduce integration costs	> believe that the existing proposed auction schedule can be improved by including opportunities to supply interim or monthly auctions that complement the annual auction process > In order to most effectively capture the opportunity of demand response in the residential sector, it is critical that aggregators have the ability to offer bids into the auction process without identifying the specific resources or customers prior to the performance period				
NRDC								
Settlement Outcome	*The Parties acknowledge the Energy Action Plans' DR goal of 5% of each IOU's peak demand by 2020 by event-based DR programs as an	*All existing IOU DR programs will retain their current System and Local RA valuation through 2019.	*Barriers will be pursued through a SR DR Integration Working Group.	The IOUs agree to seek to increase cost effective SR DR as barriers to CAISO market integration are overcome	*IOUs will submit funding and program redesign (or new programs) proposals for SR DR and LMR DR programs in their November 2015 applications.	*The Settling Parties request the CPUC to approve another three-year program cycle (2017-2019).		
	* A new goal for cost-effective DR will be determined based on a DR Potential Study that has active stakeholder participation and reflects needs identified in the LTPP, RA, TPP and other planning and procurement processes.	*Valuation of LMR DR after 2019 for reducing RA requirements and other benefits will be addressed by a LMR DR Valuation Working Group, in coordination with the Demand Analysis Working Group (DAWG) and Demand Response Measurement and Evaluation Committee (DRMEC).	*Improved CAISO integration of LMR DR will be addressed in a LMR Operations Working Group	*Parties will convene a series of working group meetings and/or workshops by December 2014 to develop the design, protocol, and standard offer contracts of a DRAM Pilot. The design, protocol and standard offer contracts will be submitted to the Commission for approval.	*A DR program can be partitioned into a LMR DR resource and a SR DR resource.	*The parties request that the CPUC conduct one (1) mid-cycle review of the IOU DR program activities, via a public workshop, which will allow for parties to provide input on potential mid-cycle revisions to the IOUs' tariffed DR programs to enhance DR program participation and performance. The IOUs could propose revisions to their tariffed DR programs based on parties' input.		

	<ul style="list-style-type: none"> The DR Goal should account for DR procurement approved in all CPUC proceedings; may be IOU specific and will include non-event based DR 	<ul style="list-style-type: none"> A SR DR resource may qualify for Local RA as a RDRR if there is a contingency trigger allowing it to show up in the Real-Time Market at a predetermined price; such resources will not count toward the cap on reliability resources adopted in D.10-06-034. 		<ul style="list-style-type: none"> An initial DRAM Pilot auction will be conducted in 2015 for 2016 delivery for SR DR providing System RA in the following minimum quantities: 10 MW for SCE, 10 MW for PG&E and 2MW for SDG&E. 		<ul style="list-style-type: none"> Parties agree to initiate a process by April 1, 2015 to develop the rules governing a potential extended DR budget cycle by December 31, 2015 for CPUC approval by March 31, 2016.
	<ul style="list-style-type: none"> All types of DR will count toward the DR Goal, both supply resource (SR) and load modifying resource (LMR). 	<ul style="list-style-type: none"> After 2015, only SR DR that meets specific reliability needs will be eligible to receive RA credit. 		<ul style="list-style-type: none"> Another DRAM Pilot auction will be conducted in 2016 for delivery beginning in 2017 and potentially beyond for SR DR providing Systems, Local and Flexible RA in the following minimum quantities: 10 MW for SCE, 10 MW for PG&E and 2 MW for SDG&E. 		<ul style="list-style-type: none"> Development of the details of an extended DR budget cycle must be coordinated with Electric Rule 24, and other key CPUC proceedings and CAISO stakeholder processes.
	<ul style="list-style-type: none"> Application of the DR Goal shall not be subject to penalties or sanctions for failure to meet the goal or to incentives to meet that goal 			<ul style="list-style-type: none"> The IOUs will not bid into the two pilot auctions but will have some discretion to select the winning bids; winning bidders will be paid as-bid. 		
	<ul style="list-style-type: none"> Future DR Goals will be firm, subject to reasonable off-ramps. 			<ul style="list-style-type: none"> IOUs will not act as the Scheduling Coordinator (SC) for the Pilot but will provide optional SC and related services to winners of the DRAM Pilot via a third party. 		
				<ul style="list-style-type: none"> The IOUs will have the option of conducting RFOs in 2015 for delivery in 2017 and beyond for SR DR and LMR DR products that differ from those procured through the DRAM Pilot. 		
				<ul style="list-style-type: none"> The IOUs' costs for the DRAM pilot will be recovered through a CPUC-authorized cost recovery mechanism, pursuant to the CPUC's decision on cost allocation in this proceeding. 		
				<ul style="list-style-type: none"> Issue to brief: Parties agree that an issue to be briefed in this proceeding and decided by the CPUC in its Settlement decision is whether the DRAM should be a preferred means of procuring Supply Resource DR and if so, how (e.g. caps or limits on IOU DR programs) . 		