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)

[PUBLIC VERSION]

THE OFFICE OF RATEPAYER ADVOCATES' OPENING COMMENTS ON PROPOSALS FOR REVISIONS TO DEMAND RESPONSE PROGRAM FOR BRIDGE FUND YEARS

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I. INTRODUCTION

The Office of Ratepayer Advocates (ORA) submits the following comments in response to the January 31, 2014 *Ruling Providing Guidance For Submitting Demand Response Program Proposals* (Ruling), in the above referenced docket. Ordering Paragraph 1 of the Ruling allows parties, other than Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE)[1], to file Demand Response (DR) program revision proposals for bridge fund years 2015 and 2016 within 30 days from the issuance of the ruling.[2]

II. SUMMARY OF RECOMMENDATIONS

ORA recommends revisions to the DR programs for the bridge funding period, as summarized below:

1. Contract terms for SCE's Aggregator Managed Portfolio (AMP) agreements should be amended to ensure contract performance.
2. The IOUs should have a reporting requirement to increase transparency to IOUs' administration of DR programs.
3. The trigger for the Base Interruptible Program (BIP) should be changed to avoid excessive expensive Non-Resource Adequacy (RA) procurement.
4. Target marketing of SmartRate to only warm climate zones.
5. Provide accurate marketing of residential Time of Use (TOU).

III. DISCUSSION

ORA supports the Commission's directive to implement DR program revisions to increase program effectiveness during the bridge funding years.[3] But before the

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[1] Ruling OP 1 orders PG&E, SDG&E and SCE to file revisions.

[2] Ruling, p. 5.

[3] ORA's Opening Comments On Proposed Decision Approving Two-Year Bridge Funding For Demand Response Programs, p. 1.

Commission embarks on enhancing the role of demand response programs envisioned in Rulemaking (R.)13-09-011, it is critical that the programs fully meet the current performance requirements. ORA's changes below reflect the **actual, recent** experience with the programs and are consistent with the Commission's guidelines in the ruling. ORA's recommended changes are designed, for the most part, to realize the expected performance when the Commission authorized the programs. Most importantly, the IOUs can implement these changes immediately, to demonstrate that they can be ready to meet the Commission's future requirements for demand response.

A. Contract Terms Of SCE's AMP Agreements Should Be Improved

Problem/Concern: ORA's review of the Aggregator Managed Portfolio (AMP) agreements of SCE in 2013 revealed issues that should be resolved before the Commission approves extending the agreements through the bridge funding years. These issues include opportunities for gaming, a capacity payment method that provides a disincentive for consistent response across all hours of an event, and flexibility in dispatch.

Recommendation: Specific contract terms should be changed to:

1. Remove opportunities for gaming by requiring SCE—not the aggregator—to determine the time of "Seller Directed Tests" (Tests) and to call Test events with the same notification as provided for dispatch events;
2. Ensure that the capacity payments are based on the actual capacity provided by AMP programs during all hours of an event rather than only the best performing hour. Also, in the event there are no subsequent events called for a DR location, SCE should use the average performance of the most recent event rather than the best performing hour when determining payments going forward.
3. Reduce notification times for test and dispatch events from one hour to 30 minutes for Day-Of DR contracts.

These changes would make the load reduction capacity of each contract more dependable, consistent and predictable and increase their availability and flexibility. In addition, the recent Petition for Modification (PFM) to implement program improvements for PG&E's Aggregator Managed Portfolio agreements based on experience gained in 2013 demonstrates that contract improvements can be implemented successfully if parties work collaboratively.[4] PG&E's contract improvements are expected to be implemented for the summer 2014 as well as the 2015-2016 Bridge funding years. ORA actively supported the contract amendments as they will contribute to continuous program improvements based on past performance. The same aggregators participate in SCE's AMP program. SCE should work with the aggregators implement improvements to contract terms described below. Based on experience with PG&E's PFM, the revisions to SCE's contracts could be implemented well before December 31, 2014.

1. The Commission Should Order SCE to Amend SCE's AMP contracts To Require SCE, Not The Seller, To Determine When To Call Seller Directed Tests And Provide The Same Notification As Provided For A Dispatch Event

SCE's 2013 and 2014 AMP agreements allow the aggregators to direct SCE on when to call Tests to set the capacity amount used to determine capacity payments, described as "Seller Directed Tests."[5] This provision was intended to afford the aggregator the opportunity to demonstrate that they are capable of delivering the Contract Capacity if they performed poorly in a "Buyer Directed Test" or a Dispatch Event. However, the ability of the seller to determine when SCE calls the "Seller Directed Test" is not consistent with the purpose of the Test. The purpose is to show that the aggregators would perform under the similar conditions to when SCE calls an actual Dispatch Event. Allowing the aggregator to specify exactly when SCE would call the Test casts doubt on whether the aggregator would perform equally well when SCE calls

[4] EnerNOC, Inc. (EnerNOC), Energy Curtailment Specialists (ECS), and PG&E jointly filed the petition to modify Decision (D.) 13-01-024. The PFM was filed on December 20, 2013 in proceeding Application (A.) 13-09-004. The petition was approved by the Commission on February 27, 2014.

[5] SCE 2013-2014 Agreements; Section 3.5.1 Seller Directed Tests.

an actual dispatch event when the aggregator does not have such specific knowledge of the timing. Test conditions should mimic actual dispatch conditions as much as possible. Moreover, the results of such Seller Directed Tests determine the capacity payment for that month, and also for subsequent months if there are no other Events dispatched. Under SCE's current DR contract structure, aggregators can game the system by knowing exactly when a Test event will occur. As such the aggregator will be able give participants notice of the exact day and time of the Test well in advance of the date so that each DR participant can plan their individual load drop (e.g., shut down operation, schedule maintenance) and potentially manipulate their individual baseline to maximize the resulting energy payment.

SCE should allow the aggregators to request a Test but the determination of when the Test would occur should be decided by SCE. SCE could commit to call the Test within a reasonable time period of 30 days. Secondly, SCE should be required to provide the same notification outlined in the AMP agreement (i.e., Day-of or Day-Ahead) for such a Test as they would in an actual Dispatch Event. Both of these changes together would eliminate the opportunity for gaming in the current Seller Directed Test and provide greater confidence that the aggregator will perform similarly when the program is dispatched in an actual event.

2. The Commission Should Order SCE To Provide Payments Based On Performance In All Hours Of Events

SCE's 2013 and 2014 AMP agreements determine payments based on the best performing hour of the most recent event in a month, and uses that best performing hour going forward.[6] For example, if they perform at 100 percent of the Contract Capacity for just one hour in the most recent event in a month, then their capacity payment is based on

[6] SCE 2013-2014 Agreements; Section 3.3 Delivered Capacity Payments. The duration of a dispatch event is typically 2-4 hours.

that best performing hour—it will not matter if they do not respond at all in all other hours of the month when the contract was dispatched. At best, this method fails to provide an incentive to perform consistently across all hours and events. At worst, the contract presents aggregators a tremendous opportunity for gaming by simply performing well during one hour at the most recent event.

Determining payments based on all hours of events encourages aggregators to provide reliable performance in every hour of every event. This change would be consistent with Resource Adequacy (RA) requirements for performance of DR programs, which require at least four consecutive hours to be RA-eligible.[7]

SCE should utilize their own best practice from the 2008 to 2012 AMP contracts in which payments were determined based on performance in all hours of the events.[8] Also, in the event there are no subsequent events called for a DR location, SCE should use the average performance of the most recent event rather than the best performing hour when determining payments going forward.

3. The Commission Should Change SCE's Day-of Notification To 30 Minutes

SCE's 2013 and 2014 AMP agreements for Day-of products require at least one hour notice to the aggregator.[9] While one hour is the minimum amount of time needed for the agreements to be dispatched in response to market conditions, the agreements do not allow for the flexibility necessary to respond to system emergencies. CAISO's System Emergency Operating Procedure No. 4420 calls on available demand response programs requiring 30 minute notification.[10] A change to 30-minute notification would also impact evaluation and modeling of these resources in supply-side proceedings,

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[7] D.11-06-022, p. 53.

[8] SCE 2008-2012 Contracts; Article 3: Compensation.

[9] SCE 2013-2014 Agreements; Section 1.6: Dispatch Notification.

[10] http://www.caiso.com/Documents/4420.pdf.

which consider fast response (30 minutes or less) demand response as "First Contingency" resources that can respond to post first-contingency conditions and would be triggered once the first major item trips offline.[11] This modification is reasonable as the aggregators manage this 30-minute response time for PG&E's AMP contracts.[12]

B. Require IOU Reporting To Increase Transparency Of IOU Administration Of DR Programs

Problem/Concern: It is not transparent how the IOU issues decisions to dispatch or not dispatch DR in the administration of its DR programs. While the ability to call these programs is based on different triggers, locations, and number of available hours, it is unclear whether the IOUs appropriately dispatch the DR programs. The IOUs have the discretion to not call DR programs even when triggers in the programs are reached, as there may be other circumstances that alter the need to call DR.[13] However, this decision making process is not transparent and DR programs may be underutilized compared to their availability and relevant avoided costs.

Recommendation: The IOUs should have regular reporting requirements throughout the DR season to improve transparency and predictability of the implementation of DR programs for the Commission. This reporting should document the decision-making process to not dispatch DR programs when triggers are met and to explain cases where peaker plants are called instead of DR.

Background: While Demand Response, along with Energy Efficiency, is at the top of the Commission's loading order[14], it is unclear how this translates to utilization of the

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[11] Rulemaking 12-03-014 Revised Scoping Ruling And Memo Of The Assigned Commissioner and Administrative Law Judge.

[12] PG&E 2013-2014 Agreements; Article 3: Obligations and Product.

[13] February 19, 2014 PG&E Least Cost Dispatch presentation to ORA.

[14] In the Energy Action Plan, adopted by the Commission in 2003, energy efficiency and demand response programs are ranked at the top of the loading order and peaker plants at the bottom. See http://www.energy.ca.gov/energy_action_plan/

programs on a day-to-day basis. For example, confidential Attachment A shows how PG&E's and SCE's AMP contracts were extremely under-utilized over the 2012 and 2013 DR seasons. Specifically, in 2012 and 2013, Attachment A shows that PG&E utilized only approximately 25% of the available hours for each of their AMP contracts. The results for SCE were even more disappointing as Attachment A shows that for 2012 and 2013, SCE utilized only approximately 10% of the available hours for the SCE AMP contracts.

Energy Division's report on *Lessons Learned From Summer 2012 Southern California Investor Owned Utilities' Demand Response Programs* (Staff Report) made similar findings as it was determined that there has been an increase in peaker plant service hours while some DR program utilization decreased from 2006 to 2012.[15] As discussed in D.13-07-003 the Commission should know and study to what extent, and why IOUs are using peaker plants at a much higher rate than demand response programs.[16]

1. IOUs Should Be Required To Explain Decision-Making When DR Programs Are Economic But Not Dispatched

The IOUs should be required to provide to Energy Division and ORA weekly exception reporting during the applicable DR season[17] that clearly identifies and describes each instance when a DR program or contract is "in the money" or is economic to dispatch but the IOU decided to utilize a non-DR resource. Providing this exception reporting on a frequent and regular basis will provide transparency into IOU DR dispatch decision-making and will facilitate the Commission and Energy Division to implement

[15] Staff Report, p.32.

[16] D.13-07-003, p.9 and Conclusion of Law #1 .

[17] Some programs are only available from May 1 to October 31 while others are available year round.

mid-season corrections if it is found the IOUs are not properly dispatching the DR programs. The reporting requirement should identify:

1. For each occurrence, of each DR program or contract, when a trigger for a DR program is met or it becomes economic to dispatch,[18]
2. Was the DR program or contract dispatched?
3. If the DR program was not dispatched, provide a detailed explanation of why not.
4. Provide the remaining hours of availability for the DR Program or contract.
5. Provide the strike price of the DR Program or contract ($/MWh or heat rate)
6. Provide the highest energy price (NP15 for PG&E; SP15 for SCE and SDG&E) relevant for comparison with the lead time of the program (day ahead or day of). If the IOU uses a different metric, such as default Load Aggregation Point (dLAP) price, identify that metric and provide the highest energy price.
7. Provide the highest cost resource that was dispatched instead of the DR Program or contract.
8. Provide the forecast and actual locational marginal price from the CAISO market that was most relevant to the identified DR program.

Table 1 provides a draft template for input of some of this information.

[18] Triggers may vary between AMP contracts so specific AMP contracts could be identified if only some are triggered.

Table 1: ***Draft Reporting Template***

Date Trigger Is Met	Program or Contract	Specify Trigger	Dispatch (Y/N)	If No, Explain	Remaining Availability	Highest Price non-DR resource Dispatched
05/15/2014	Name of DR Program or Contract	Heat Rate of 15,000 BTU/kWh or $200/MWh	N	Participant Fatigue	80 hours	$500/MWH Peaker # 1

This reporting requirement would allow ORA and the Commission to review the decisions of the IOUs in administering these programs, make mid-DR season adjustments, and inform future program design.

This information would also provide essential information for the Commission and ORA to properly review IOUs' decisions in the Energy Resource Recovery Account (ERRA) proceedings, which reviews utility contract administration on an annual basis.[19] The IOUs should work collaboratively with ORA and Energy Division to establish a template for future use and submit it to the Commission for review and approval through an Advice Letter. Such a requirement should be established in time for the 2014 DR season as well as the 2015-2016 DR seasons.

C. The Trigger For BIP Should Be Changed To Avoid Excessive Expensive Non-RA Procurement

Problem/Concern: Currently the BIP could be used when the California Independent System Operator (CAISO) has used up all resources (RA and Non-RA) in its balancing authority and needs to canvas neighboring balancing authorities and other

[19] Currently only PG&E's AMP is reviewed in ERRA.

entities for available Exceptional Dispatch (ED)[20] energy/capacity to maintain grid reliability. Because BIP is an RA resource already paid for by ratepayers, the CAISO should be able to use BIP before procuring any Non-RA resources within the CAISO's own balancing authority.

Recommendation: The trigger for the BIP should be moved to an earlier Step in CAISO's Operating Procedure 4420[21] to allow for BIP dispatch ***before*** the CAISO procures costly Exceptional Dispatch energy or capacity from Non-RA sources within its ***own*** balancing authority. This change is necessary so ratepayers will avoid paying twice (once through BIP program costs and again through Exceptional Dispatch procurement of Non-RA resources) for the same capacity BIP was intended to provide.

Background: In Decision ("D.") 10-06-034, the Commission adopted a Reliability-Based Demand Response Settlement (Settlement)[22] that required the CAISO to initiate a stakeholder process in 2010, with the objective of developing a wholesale reliability demand response product (RDRP) that is compatible with the IOUs' reliability-based demand response programs.[23] The Settlement also required IOUs to transition their reliability-based demand response programs to be compatible with RDRP[24] by end of 2014.[25] On May 20, 2011, the CAISO filed with FERC the tariff amendments to

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[20] Under California's Market Redesign and Technology Upgrade (MRTU), reliability requirements that cannot be resolved through the California ISO market software will be met by manually issued Exceptional Dispatches.
http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/ExceptionalDispatch.aspx

[21] See CAISO Operating Procedure 4420 Version 8.4 Effective January 9, 2014 Section 3.3.2 Warning Notice Step 12. http://www.caiso.com/Documents/4420.pdf.

[22] D.10-06-034 Appendix A.

[23] D.10-06-034, Appendix A, p. 3.

[24] The corresponding name in CAISO's tariff is called Reliability Demand Response Resource ("RDRR").

[25] Currently, only the BIP program remains as a reliability-based program.

incorporate RDRP in the CAISO's wholesale markets.[26] On August 19, 2013, the CAISO resubmitted its RDRP tariff revisions and requested that the FERC accept the tariff revisions contained in the compliance filing effective April 1, 2014.[27] The FERC approval of CAISO's tariff amendments is currently pending.

Parties to the Settlement agreed that no party would request any further changes to the RDRP trigger until December 31, 2014.[28] ORA is a party to the Settlement. Since the proposed change to the BIP trigger would be implemented by the utilities in their tariff and by the CAISO in its Operating Procedure in 2015, the proposed change is consistent with the settlement terms. Although the CAISO will need to modify its Operating Procedure 4420 consistent with the proposed BIP trigger, any additional FERC approval would not be needed.

1. Modify The BIP Trigger To Allow Dispatch Before Procurement of Non-RA Resources

The main feature of the RDRP product design is its system trigger. Under the Settlement, the RDRP product design modified the existing system trigger from pre-Stage 1 imminent to the point immediately prior to the CAISO need to canvas neighboring balancing authorities and other entities for available Exceptional Dispatch energy/capacity. In other words, the DR resources are eligible for dispatch once the CAISO has issued a Warning Notice under its Emergency Operating Procedures and immediately prior to the CAISO need to seek available Exceptional Dispatch energy/capacity from neighboring balancing authorities and other entities.[29]

In adopting the new trigger specified in the Settlement, the Commission noted,

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[26] http://www.caiso.com/Documents/2011-05-20_RDRRAmendment_ER11-3616-000.pdf

[27] http://www.caiso.com/Documents/Aug19_2013Compliance-ReliabilityDemandResponseResourceER13-2192-000.pdf

[28] D.10-06-034 Appendix A, p. 5.

[29] D.10-06-034, Appendix A, Section A.4.l.

> [M]ost importantly, the reliability-triggered demand response program will be triggered prior to the California Independent System Operator's canvassing of neighboring balancing authorities for energy or capacity. This new practice would eliminate the anomalous treatment whereby emergency-triggered demand response counts for Resource Adequacy yet, unlike all other power that counts for Resource Adequacy, the California Independent System Operator currently procures costly 'exceptional dispatch energy or capacity' before using this energy resource, a practice that has led to charges that ratepayers 'pay twice' for this power.[30]

Based on the above, the Commission envisioned that, at a minimum, the new RDRP-related system trigger in the Settlement would allow the CAISO to use the IOUs' emergency-triggered demand response programs before procuring the costly Exceptional Dispatch energy or capacity.[31] The IOUs' ratepayers make substantial payments to participants in these emergency-triggered programs and should expect all possible cost savings in return.

The RDRP product design allows the CAISO to dispatch the emergency-triggered DR programs prior to canvassing neighboring balancing authorities for available Exceptional Dispatch energy/capacity.[32] Because the CAISO only rarely needs to canvas neighboring balancing authorities for power, the trigger accommodated the primary features of the existing IOU reliability-based DR programs and also took into account the business needs of current participants in the programs.

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[30] D.10-06-034, p. 2.

[31] http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/CapacityProcurementMechanism.aspx On April 1, 2011 the CAISO implemented a new capacity procurement mechanism (CPM) to replace the Interim Capacity Procurement Mechanism, updated the price paid for capacity and extended bid mitigation applicable to Exceptional Dispatches. The new CPM procures capacity that is not already designated as resource adequacy capacity (RA) and is obligated to be available to the ISO for scheduling and dispatch comparable to the obligations of resource adequacy capacity.

[32] D.10-06-034, p.14 and Findings of Fact # 8.e.

The current RDRP trigger adopted in the settlement still does not allow triggering of emergency-triggered DR programs if other Non-RA resources are eligible for Exceptional Dispatch Capacity Procurement Mechanism (CPM) designation within the CAISO's own balancing authority.[33] This issue was discovered by ORA after the settlement was adopted. If such Non-RA resources are available, CAISO has to procure them first, prior to triggering RDRP. In order for emergency-triggered DR programs to be truly used for avoiding procurement of any Exceptional Dispatch capacity from non-RA resources by CAISO, the RDRP trigger needs to be further modified. Otherwise, IOUs' ratepayers would again end up paying twice for the same Exceptional Dispatch capacity from Non-RA resources within CAISO's balancing authority that the emergency-triggered DR programs were expected to avoid. Emergency-triggered DR programs should be available to CAISO to avoid buying expensive Non-RA Exceptional Dispatch capacity using CPM, whether it is procured within its own balancing area or from neighboring balancing authorities.[34] T able 2 below depicts the evolution of the trigger with ORA's recommendation.

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[33] See CAISO Procedure for "Operating Reserve Deficiency" in Section 3.3.2, Step 12. http://www.caiso.com/Documents/4420.pdf.

[34] Because of the recent FERC action, the Exceptional Dispatch capacity has become even more expensive. In a recent all-party settlement, in CAISO Docket No. ER11-2256, the FERC raised the fixed CPM capacity price from $55/Kw-year to $67.50 kW/-year for 2012 and 2013, with a further increase to $70.88 /kW-year after February 16, 2014. In that settlement, for "non-system reliability" needs the FERC doubled the minimum period of capacity payment (from 30 days to 60 days). If the CAISO needs to acquire Exceptional Dispatch capacity from Non-RA resources within its own balancing authority, under the current Settlement the CAISO will have to procure it before triggering RDRP, and the ratepayers will bear the increasing and substantial burden of this double payment. Even with this proposed change in the trigger, RDRP would be used sparingly. See Table 3 below for a comparison in frequency of utilization under different triggers. http://www.ferc.gov/whats-new/comm-meet/2012/021612/E-8.pdf.

Table 2: *Evolution of BIP Program Trigger*

After January 19, 2009	RDRP tariff pending approval at FERC	ORA's Proposal
Resolution E-4220	D. 10-06-034, Appendix A	Bridge Funding in 2015
- CAISO forecasts a Stage 1 emergency and issues a Warning - CAISO takes all necessary steps to prevent further degradation of its operating reserves under emergency operating procedure E-508B. - BIP is dispatched if CAISO determines a Stage 1 emergency is imminent	- CAISO forecasts a Stage 1 emergency and issues a Warning - CAISO takes all necessary steps to prevent further degradation of its operating reserves under emergency operating procedure E-508B - CAISO issues a Market Notice and designates available Exceptional Dispatch capacity/energy within its own balancing authority, including Non-RA resources as needed - BIP is dispatched just prior to CAISO need to canvas neighboring balancing authorities and other entities for available Exceptional Dispatch capacity/energy	- CAISO forecasts a Stage 1 emergency and issues a Warning - CAISO takes all necessary steps to prevent further degradation of its operating reserves under emergency operating procedure E-508B within its own balancing authority - CAISO considers BIP as an alternative before procuring Non-RA Exceptional Dispatch capacity/energy under its CPM process within its own balancing authority. BIP can be dispatched as appropriate for the issue.

ORA's proposal would allow BIP to be considered as a potential alternative before CAISO procures Exceptional Dispatch capacity from a Non-RA resource to backstop RA capacity under its CPM. In 2011, CAISO procured ED under CPM once for system energy reliability as a result of a power outage, which BIP may have been able to respond to.[35] In 2012, CAISO procured ED under CPM several times but in some cases for voltage support – BIP is not an appropriate resource for that - Huntington Beach Units 3 and 4 were.[36] Table 3 shows when ED CPM was issued, the reason for the procurement and whether BIP may have been an alternative to the procurement under ORA's recommended change in the trigger.[37] It shows that under ORA's recommended trigger, BIP could have been considered as an alternative to Non-RA CPM once in 2011, three times in 2012, once in 2013 and once in 2014 thus far.

Table 3: ***Consideration of BIP Under ORA's Recommended Trigger***[38]

Date*	Reason	BIP may have been an alternative to Non-RA CPM
9/8/2011	System energy reliability	Yes
2/8/2012	Resource outages in southern Orange County and the San Diego territory	Yes
3/1/2012	On-going outages in southern Orange County and the San Diego territory	Yes
5/1/2012	Non-system reliability need	Yes
5/11/2012	Voltage support	No
6/10/2012	Voltage support, extension of 5/11/2012 designation	No
8/9/2012	Voltage support, extension of 6/10/2012 designation	No
9/5/2012	Voltage support	No

[35] CPM Designation Report September 2011 http://www.caiso.com/Documents/CapacityProcurementMechanismDesignationReportSeptember2011.pdf.

[36] According to CAISO, BIP cannot provide the same sustained performance needed for voltage support that Huntington Beach units 3 and 4 could provide. Email communication from CAISO on 8/28/2012.

[37] BIP may not have been applicable under all circumstances but ORA's recommendation is to allow the CAISO to consider it as an option before procuring Non-RA CPM and to dispatch it if BIP is appropriate.

[38] 2011-2013 CPM reports: http://www.caiso.com/Documents/MARKET%20-26-%20OPERATIONS/Reports%20and%20bulletins/Reports%20and%20bulletins%20archive/Capacity%20procurement%20mechanism%20reports%20archive

2014 CPM reports: http://www.caiso.com/Documents/MARKET%20-26-%20OPERATIONS/Reports%20and%20bulletins/Market%20reports/Capacity%20procurement%20mechanism.

2/22/2013	Morro Bay-Midway 230kV line outages	Yes
10/30/2013	Ensure contingency plan for loss of Barre-Ellis #1 and #2 or common tower of Barre-Ellis #3 and #4	No
2/6/2014	Low gas inventories forcing multiple natural gas units to reduce output	Yes[39]

*By February 26, 2014.

BIP as an RA resource (it receives CPUC RA credit) should be considered as a potential solution to meet the need before CAISO procuring expensive ED capacity at $70.88/kw-year, typically for a 30 day period. Since BIP would still be called rarely, ORA's proposal would be consistent with the business needs of these large BIP customers who are currently only called during near emergency conditions.

Summary

BIP as an RA resource (it receives CPUC RA credit) should be considered as a potential solution to meet the need before CAISO procures expensive ED capacity at about $70.88/kW-year for up to 60 day period. Since BIP would still be called rarely, as shown in Table 3, ORA's proposal would be consistent with the business needs of BIP customers who are normally called during near emergency conditions. The proposal is consistent with the Commission's intent in D.10-06-034, i.e., reliability DR programs should help avoid CAISO's procurement of Exceptional Dispatch energy or capacity. Given the uncertainty in regards to approval of RDRP and the timeframe in which reliability-based DR programs would be able to participate in RDRP, the triggers of the programs in the IOUs' tariffs should be moved to prior to CAISO's procurement of Non-RA Exceptional Dispatch within its own balancing authority.

D. Target Marketing Of SmartRate To Only Warm Climate Zones

Problem/Concern: The current marketing effort of SmartRate is not targeted. Marketing of SmartRate, PG&E's residential critical peak pricing (CPP) program, in the

[39] BIP was dispatched on this day.

cool regions of the Greater Bay Area and Northern Coast provides much less load reduction per participant compared to the estimated response from marketing in other warmer regions.

Recommendation: PG&E should target their SmartRate marketing dollars to customers in other areas where load reductions could provide greater impact/system benefits, and substantially reduce marketing efforts to customers in cool, coastal areas.

Background: Participation in SmartRate increased from approximately 21,000 customers at the end of 2011 to 78,000 by October 2012.[40] The bulk of this increase in customer participation came from the cool region of the Greater Bay Area, where participation increased from approximately 4,900 customers to 27,200 customers. However, the average load reduction of participants in the Greater Bay Area is far less than those of all other local capacity areas (LCA). Tables 4-3 and 4-4 of PG&E's 2012 Load Impact Evaluation of Residential Time-based Pricing Programs show the average hourly load reduction for seven of the eight LCAs in PG&E's service territory for SmartRate-only and dually-enrolled customers (with SmartAC), respectively.[41]

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[40] PG&E 2012 Load Impact Evaluation of Residential Time-based Pricing Programs, p.1.

[41] Id. These tables use the average number of enrolled customers across the 10 event days in 2012 which is less than the 78,000 participants in October 2012, p.26 and p.33.

Table 4-3: SmartRate Average Hourly Load Reduction for Event Period (2 to 7 PM) by Local Capacity Area (SmartRate-only Participants)

Local Capacity Area	# of SmartRate Customers	Avg. Reference Load (kW)	Avg. Load Reduction (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Average Temp. During Event (°F)
Greater Bay Area	15,922	0.77	0.10	13%	1.6	79
Greater Fresno	4,036	2.21	0.31	14%	1.3	100
Kern	5,360	2.43	0.27	11%	1.4	99
Northern Coast	1,582	0.95	0.17	18%	0.3	88
Other	5,648	1.62	0.26	16%	1.5	93
Sierra	2,761	1.94	0.50	26%	1.4	94
Stockton	2,984	1.89	0.29	15%	0.9	94
Total	**38,667**	**1.44**	**0.20**	**14%**	**7.9**	**89**

Table 4-4: SmartRate Average Hourly Load Reduction for Event Period (2 to 7 PM) by Local Capacity Area (Dually-enrolled Participants)

Local Capacity Area	# of SmartRate Customers	Avg. Reference Load (kW)	Avg. Load Reduction (kW)	% Load Reduction	Aggregate Load Reduction (MW)	Average Temp. During Event (°F)
Greater Bay Area	8,817	1.21	0.28	23%	2.5	85
Greater Fresno	2,542	2.39	0.56	24%	1.4	99
Kern	1,288	2.70	0.69	26%	0.9	99
Northern Coast	1,353	1.16	0.29	25%	0.4	86
Other	3,355	1.74	0.47	27%	1.6	95
Sierra	2,698	2.07	0.61	30%	1.7	94
Stockton	2,030	1.95	0.49	25%	1.0	94
Total	**22,132**	**1.65**	**0.42**	**25%**	**9.2**	**91**

1. Targeted Marketing

As the tables above indicate, the Greater Bay Area and Northern Coast have much lower average reference loads and much lower average load reductions among participants compared to other LCAs in PG&E's service territory. The relatively high aggregate load impact of the Greater Bay Area comes from the greater number of participants and thus is a less meaningful statistic than average load reductions. Based on average load reduction, targeted marketing to increase participation in warmer LCAs would create greater load reduction than further marketing to increase participation in the Greater Bay Area and Northern Coast. PG&E should target its marketing to warmer LCAs, where the limited marketing funds would be more effective in providing load reduction, and it should substantially reduce marketing SmartRate in cool, coastal areas.

E. Provide Accurate Marketing of Residential Time Of Use

Problem/Concern: Changes to opt-in residential TOU rates are currently under development and the Commission currently is considering default residential TOU in 2018.[42] Marketing of residential TOU at this time may confuse customers as changes are expected and may contradict what is currently advertised.

Recommendation: Focus the marketing of residential TOU so to ensure that the advertising does not mislead the customer.

Background: SCE has proposed a mid-year 2014 opt-in TOU rate in Application (A.)13-12-015 and SDG&E has proposed opt-in TOU for all residential customers by January 2015 in A.14-01-027. Under California Assembly Bill (AB) 327, the Commission may authorize default residential TOU in 2018.[43]

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[42] R.12-06-013 Appendix A, p. 1.

[43] AB 327 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

1. Residential TOU Marketing Should Be Accurate

For residential customers, marketing of TOU rates should be focused on educating them about the potential impacts of a rate change from tiered rates to TOU will have on their billing. IOU ratepayers may face rate increases larger than inflation expectations for the next few years. While the customers who can reduce their usage in peak hours will likely benefit with optional TOU, the customers who are able to reduce their overall usage (but not necessarily in peak hours) may be better off staying with current tiered rates. General outreach/education information for now should provide customers the ability to monitor their usage pattern and compare tiered and optional TOU rates to see which rate can help them mitigate bill increases. Marketing should not mislead customers to assuming that their rate will decrease with TOU as this may upset those customers who cannot reduce usage in peak hours and lead to opt outs.

SCE and SDG&E should also consider combining the outreach/education effort for TOU with outreach for their opt-in Peak Time Rebate programs.[44] Integrated marketing would make the information more accessible to the customer and may be more effective in enrolling customers for both the TOU rate and the PTR program. It also makes clearer the choices that are available to customers.

IV. CONCLUSION

ORA's recommendations are all data-based on the actual recent experience with the programs and are consistent with the Commission's guidelines in the ruling. ORA's changes are designed, for the most part, to realize the expected performance when the Commission first authorized the programs. The IOUs can implement these changes right now, to demonstrate that they can be ready to meet the Commission's future requirements for demand response going forward.

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[44] D.13-07-003 OP 8 required SCE and SDG&E to revise their PTR program tariffs to be opt-in instead of default. PG&E does not offer PTR.

In summary, before the Commission embarks on enhancing the role of demand response programs envisioned in Rulemaking (R.)13-09-011, it is critical that the 2015-2016 programs fully meet the current performance requirements. ORA strongly supports the Commission's directive to implement DR program revisions to continually improve program effectiveness during the bridge funding years.

Respectfully submitted,

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ATTACHMENT A

PUBLIC VERSION

PG&E and SCE Aggregator Managed Portfolio Events
in 2012 and 2013

Table 1: 2012 PG&E AMP[1]

Aggregator Contract called	Contract Type	Date of event	Trigger Condition	Hour Event Started	Hour Event Ended	Time of notification	Load Reduction Dispatched	Load Impact Delivered (used for settlement)	Ex Post Load Impact	Hours Called		
Alternative Energy Resources	X	X	X	X	X	X	X	X	X	X	Total Hours Called	X
		x	x	x	x	x	x	x	x	x	Total Hours Available	x
		x	x	x	x	x	x	x	x	x	% of Available Hours Used	x
Energy Curtailment Specialists	x	x	x	x	x	x	x	x	x	x	Total Hours Called	x
		x	x	x	X	X	X	X	X	X	Total Hours Available	x
		x	x	X	X	X	X	X	X	X	% of Available Hours Used	x
Energy Connect	X	X	X	X	X	X	X	X	X	X	Total Hours Called	x
		X	X	X	X	X	X	X	X	x	Total Hours Available	x
		X	X	X	X	X	X	X	X	X	% of Available Hours Used	x
EnerNOC		X	X	X	X	X	X	X	X	X	Total Hours Called	x
		X	X	X	X	X	X	X	X	X	Total Hours Available	x
		X	X	X	X	X	X	X	X	X	% of Available Hours Used	x

[1] Data from PG&E response to data request "DRA-DR_PG&E003 (2013)" and AMP agreements approved in D.12-04-045 through 2012

Table 2: 2013 PG&E AMP[2]

Aggregator Contract called	Contract Type	Date of event	Trigger Condition	Hour Event Started	Hour Event Ended	Time of notification	Load Reduction Dispatched	Load Impact Delivered (used for settlement)	Hours Called		
Alternative Energy Resources	X	X	X	X	X	X	X	X	X	Total Hours Called	X
		X	X	X	X	X	X	X	X	Total Hours Available	X
		X	X	X	X	X	X	X	X	% of Available Hours Used	X
		X	X	X	X	X	X	X	X		
Constellation NewEnergy	X	X	X	X	X	X	X	X	X	Total Hours Called	X
		X	X	X	X	X	X	X	X	Total Hours Available	X
		X	X	X	X	X	X	X	X	% of Available Hours Used	X
		X	X	X	X	X	X	X	X		
		X	X	X	X	X	X	X	x		
Energy Curtailment Specialists	X	X	X	X	X	X	X	X	X	Total Hours Called	X
		X	X	X	X	X	X	X	X	Total Hours Available	X
		X	X	X	X	X	X	X	X	% of Available Hours Used	X
		X	X	X	X	X	X	X	X		
		X	X	X	X	X	X	X	x		

[2] Data from PG&E response to data request "DRA-DR_PG&E005 (2013) Supplemental 2" and AMP agreements approved in D.13-01-024

		X	X	X	X	X	X	X	x
		X	x	X	X	X	X	X	x

Energy Connect	X	X	X	X	x	X	X	X	X	Total Hours Called	x
		X	X	x	x	X	X	X	X	Total Hours Available	X
		X	X	X	X	X	X	X	X	% of Available Hours Used	X
		X	X	X	X	X	X	X	X		
		X	X	X	X	X	X	X	X		
		X	X	X	X	X	X	X	x		

Energy Connect	X	x	x	X	X	X	X	X	X	Total Hours Called	x
		X	X	X	X	X	X	X	X	Total Hours Available	X
		X	X	X	X	X	X	X	X	% of Available Hours Used	x
		X	X	X	X	X	X	X	X		
		X	X	X	X	X	X	X	x		

EnerNOC	X	X	X	X	X	X	X	X	X	Total Hours Called	x
		X	X	X	X	X	X	X	X	Total Hours Available	x
		X	X	X	X	X	X	X	X	% of Available Hours Used	x
		X	X	X	X	X	X	X	x		
		X	X	X	X	X	X	X	x		

EnerNOC	X	X	X	X	X	X	X	X	X	Total Hours Called	x
		X	X	X	X	X	X	X	X	Total Hours Available	x
		X	X	X	X	X	X	X	X	% of Available	x

										Hours Used	
		X	X	X	X	X	X	X	x		x

Table 3: 2012 SCE AMP[3]

Aggregator Contract called	Contract Type	Date of event	Trigger Condition	Hour Event Started	Hour Event Ended	Time of notification	Load Reduction Dispatched	Load Impact Delivered (used for settlement)	Ex Post Load Impact	Hours Called		
Constellation	X	x	x	X	X	x	x	x	x	x	Total Hours Called	x
											Total Hours Available	x
											% of Available Hours Used	x
Constellation	x	x	x	x	x	x	x	x	x	x	Total Hours Called	x
											Total Hours Available	x
											% of Available Hours Used	x
EnerNoc	x	x	x	x	x	x	x	x	x	x	Total Hours Called	x
		x	x	x	x	x	x	x	x	x	Total Hours Available	x
											% of Available Hours Used	x
NAPP	x	x	x	x	x	x	x	x	x	x	Total Hours Called	x
		x	x	x	x	x	x	x	x	x	Total Hours Available	x
											% of Available Hours Used	x

[3] Data from SCE response to data request "DRA-DR_SCE002 (2013)" and AMP agreements approved in D.08-03-017 through 2012

Table 4: 2013 SCE AMP[4]

Aggregator Contract called	Contract Type	Date of event	Trigger Condition	Hour Event Started	Hour Event Ended	Time of notification	Load Reduction Dispatched	Load Impact Delivered (used for settlement)	Hours Called		
Constellation NewEnergy	x	x	x	x	x	x	x	x	x	Total Hours Called	x
		x	x	x	x	x	x	x	x	Total Hours Available	x
		x	x	x	x	x	x	x	x	% of Available Hours Used	x
		x	x	x	x	x	x	x	x		
Energy Curtailment Specialists	x	x	x	x	x	x	x	x	x	Total Hours Called	x
		x	x	x	x	x	x	x	x	Total Hours Available	x
		x	x	x	x	x	x	x	x	% of Available Hours Used	x
		x	x	x	x	x	x	x	x		
		x	x	x	x	x	xx	x	x		
		x	x	x		x	x	x	x		
		x	x	x		x	x	x	x		
		x	x	x		x	x	x	x		
		x	x	x		x	x	x	x		

[4] Data from SCE response to data request "DRA-DR_SCE004 (2013) Supplemental 2" and AMP agreements approved in D.13-01-024

Energy Connect	x	x	x	x	x	x	x	x	x	Total Hours Called	x
		x	x	x	x	x	x	x	x	Total Hours Available	x
		x	x	x	x	x	x	x	x	% of Available Hours Used	x

ENERNOC	x	x	x	x	x	x	x	x	x	Total Hours Called	x
		x	x	x	x	x	x	x	x	Total Hours Available	x
		x	x	x	x	x	x	x	x	% of Available Hours Used	x
		x	x	x	x	x	x	x	x		
		x	x	x	x	x	x	x	x		

NAPP	x	x	x	x	x	x	x	x	x	Total Hours Called	x
		x	x	x	x	x	x	x	x	Total Hours Available	x
		x	x	x	x	x	x	x	x	% of Available Hours Used	x