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)

THE OFFICE OF RATEPAYER ADVOCATES' COMMENTS ON DEMAND RESPONSE PROGRAM BRIDGE FUNDING AND STAFF PILOT PROPOSALS

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AMENDED PUBLIC VERSION

Notice to Parties:
Footnotes 16 and 18, which were previously redacted, are now public.

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I. INTRODUCTION

The Office of Ratepayer Advocates (ORA) submits the following comments in response to the *Order Instituting Rulemaking To Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements* (Rulemaking), in the above referenced docket. Ordering Paragraph 2 of the Rulemaking directs parties to provide responses to a set of six questions regarding demand response (DR) program bridge funding and Energy Division's proposals for pilots.[1]

II. DISCUSSION

ORA supports both bridge funding and pilots, provided the Commission order the utilities amend the programs during the bridge funding year. ORA sees bridge funding as a unique opportunity to increase program effectiveness and to prepare them for the future role envisioned in the Rulemaking. As explained below, the Commission can implement DR program changes right now, based on recent experience. ORA also provides recommendations concerning funding and design of the proposed pilots.

A. Bridge Funding For 2015 Is Reasonable If Changes Are Made To Current Demand Response Programs

The Rulemaking poses the question of whether it is reasonable to authorize one-year bridge funding for the demand response programs, and to continue *as they are in 2015,* while the Commission contemplates changes to the structure of the overall demand response program.[2]

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[1] R.13-09-011, p. 27.

[2] Decision 12-04-045 Ordering Paragraph 85 directed Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company's (SDG&E) (Utilities) to file demand response applications for the 2015-2017 program cycle no later than January 31, 2014. In a letter to the Commission dated July 29, 2013, the Utilities requested a 6-month extension of time to comply with the Order based on indication from Commission staff that a new Rulemaking would be issued with consideration for a bridge funding year for 2015. On September 18, 2013, the Commission's Executive Director, Paul Clanon, granted the Utilities' request for a 6 month extension to file their next demand response applications. Mr. Clanon's letter extended the filing date from January 31, 2014 to July 31, 2014.

ORA agrees one-year bridge funding is reasonable. Given the likelihood that this Rulemaking would result in making significant changes to DR programs, there is more than ample time to consider necessary and attainable changes to programs for 2015 operations. Below, ORA makes specific recommendations on the IOUs' the Base Interruptible Program (BIP) and Aggregator Managed Portfolio (AMP) agreements. The changes ORA proposes are intended to clarify administration of the programs and ensure that the programs provide the benefits that were expected from them when the Commission approved these programs. IOUs provide generous capacity payments for these DR programs based on the assumed avoided cost of a new combustion turbine (CT). But, based on ORA's analysis, some of the program design features and contract language prevent these programs from providing the intended benefits to the California Independent System Operator (CAISO) and ratepayers.

B. The Trigger for Reliability-Based Programs Should Be Changed To Avoid Excessive Expensive Procurement

The trigger for reliability-based programs and the CAISO's reliability demand response product (RDRP) should be moved to allow for dispatch before the CAISO procures costly Exceptional Dispatch energy or capacity within its ***own*** balancing authority.

In Decision ("D.") 10-06-034, the Commission adopted a Reliability-Based Demand Response Settlement (Settlement)[3] 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.[4] The Settlement also required IOUs to transition their reliability-based demand response programs to be compatible with RDRP by end of 2014. On May 20, 2011, the CAISO filed with FERC the tariff amendments to

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

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

incorporate RDRP in the CAISO's wholesale markets.[5] 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.[6] The FERC approval of CAISO's tariff amendments is currently pending. If RDRP is approved, it is uncertain when each utilities' reliability-based programs would be prepared to participate in RDRP.

The main feature of the RDRP product design is its system trigger. Under the Settlement, the RDRP product design would modify 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 would be 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.[7]

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

> [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

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

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

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

> capacity' before using this energy resource, a practice that has led to charges that ratepayers 'pay twice' for this power.[8]

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. The IOUs' ratepayers make substantial payments to participants in these emergency-triggered programs and should expect all possible cost savings in return.

At the time, it was ORA's focus to move the emergency-triggered programs inside the tent of CAISO's Automated Dispatch System (ADS) and normal notification channels used for dispatching other generation resources.[9] The RDRP product design appeared to meet that objective. It allowed the CAISO to dispatch the emergency-triggered DR programs prior to canvassing neighboring balancing authorities and other entities for available Exceptional Dispatch energy/capacity. 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.[10]

The current anticipated RDRP trigger still does not allow triggering of emergency-triggered DR programs if other Non-RA (also Non-RMR, Non-CPM) resources are eligible for Exceptional Dispatch Capacity Procurement Mechanism (CPM) designation within the CAISO's own balancing authority. If such Non-RA resources are available, the CAISO would have 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 by CAISO, the RDRP trigger needs to be further

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

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

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

modified. Otherwise, IOUs' ratepayers would again end up paying twice for the same Exceptional Dispatch capacity that the emergency-triggered DR programs were expected to avoid. Emergency-triggered DR programs should be available to CAISO to avoid buying expensive Exceptional Dispatch capacity, whether it is procured within its own balancing area or from neighboring balancing authorities.[11] Table 1 of Attachment A depicts the evolution of the trigger with ORA's recommendation. ORA understands that the CAISO supports the change ORA is recommending.

Keeping with the Commission's intent in D.10-06-034, the Commission should modify the RDRP system trigger so that the reliability-based DR programs are available to the CAISO prior to soliciting any Non-RA resources within its own balancing authority. 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 also be moved to prior to CAISO's procurement of Exceptional Dispatch within its own balancing authority. These changes can be made for bridge funding of the programs in 2015.

C. Utility Administration Of AMP Agreements Should Be Clarified

Administrative issues have been revealed through the performance of the Aggregator Managed Portfolio agreements in 2013. These issues must be resolved to allow more effective administration of the agreements before bridge funding is approved for 2015.

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[11] 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 in 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. For example, the CAISO has not procured any Exceptional Dispatch capacity for reliability purposes in 2012 from within its own balancing authority.

1. The May 31st Test Event Requirement Should Be Retained in 2015 Extensions

D.13-01-24 approved AMP agreements for 2013 and 2014. To ensure the AMP programs can provide the contracted capacity, Ordering Paragraph 5 requires PG&E and SCE to perform a demand response test event early in each contract season, but no later than May 31st.[12] The testing requirement was not explicitly written in the contract, nor negotiated by the parties, but required as reasonable per Commission order.[13] PG&E and SCE complied in 2013, and the test event results revealed several aggregators failed to perform.[14]

As a condition for bridge funding, the Commission should make it explicit that AMP contract capacity testing is required for PG&E and SCE early in 2015, but no later than May 31st.

2. PG&E Should Call Re-Tests In A Reasonable Time Frame

PG&E's agreements allow aggregators to provide them with a Notice of a request for an Event Re-Test when they do not provide their contracted capacity in an Event Test.[15] PG&E then has the discretion to schedule a Re-Test, however, no timeframe is provided for scheduling the Re-Test.[16] PG&E should introduce a reasonable time (ORA recommends thirty days from the Notice) to conduct Re-Tests to allow aggregators the opportunity to improve on their Test results. Such a change would facilitate the application of performance results for Event Tests and Event Re-Tests for capacity

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[12] D.13-01-024 p. 35.

[13] Executive Director Paul Clanon's May 20, 2013 letter RE: CORRECTION PG&E's Request for Two-Week Extension of Time for the May 2013 Aggregator Managed Portfolio Test Event Ordered in Decision 13-01-024.

[14] PG&E Data Request Response "DemandResponseRFO-2013_DR_DRA_008-Q01-03" and SCE Data Request Response "DATA REQUEST SET A.12-09-007-DRA-SCE-002".

[15] PG&E 2013-2014 Agreements; Section 3.5 Testing.

[16] In 2013, Re-Tests of Event Tests in May were not called until August. PG&E Data Request Response "DemandResponseRFO-2013_DR_DRA_008-Q01-03".

payments on a forward basis without putting aggregators at a disadvantage when they perform poorly in a Test and request a Re-Test.

D. Contract Terms Of AMP Agreements Should Be Improved

Performance of the Aggregator Managed Portfolio agreements of PG&E and SCE in 2013 has revealed issues that should be resolved before bridge funding is approved for extending AMP programs for 2015. Specific contract terms should be changed to ensure that the capacity payments are based on the actual capacity provided by AMP programs during each month of the contract term. All of ORA's following recommendations in terms of AMP program contract terms are intended to incorporate best practices from either previous iterations of AMP contracts or best practices currently incorporated in the 2013-2014 AMP contracts by one IOU or the other. None of ORA's following recommendations should be construed as "new" requirements for 2015 contract extensions.

1. Payments for PG&E's AMP Agreements Should Be Based On The Performance During the Most Recent Event.

Under PG&E's AMP agreements for 2013 and 2014, aggregators have the ability to request an Event Re-Test when their performance in a DR Event Test is less than the Commitment Level of the contract. If the result of the Event Re-Test is higher than performance in the Event Test, the higher performance is used to determine the capacity payments from the month of the original Test until the month of a subsequent event.[17] This particular contract language has resulted in an unfair situation for ratepayers in that the AMP contracts are being paid for all the intervening months between a Test and a Re-Test at the rate of maximum capacity demonstrated by the original Test or by the Re-Test. The Re-Test can be performed several months later after the original failed test.

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[17] PG&E 2013-2014 Agreements; Section 3.5 Testing.

There is no requirement to demonstrate that during all the intervening months the aggregator actually has the capacity at the Re-Test level.[18]

The performance of Re-Tests should not be used retroactively to determine payments for previous months since the aggregator has not demonstrated that they were able to provide that performance in the previous months. Instead, the performance in Event Tests, Event Re-Tests and Dispatch Events should only apply to the month in which the Event occurred and the results from the most recent event should be used for subsequent months, until another Event occurs. Again, this is not a new requirement but rather a best practice that is currently implemented by the SCE AMP contracts.[19]

2. SCE's Agreements To Reintroduce Penalties For Poor Performance

SCE's 2013 and 2014 agreements attempt to motivate good performance through the ability to call unlimited Events and terminate the contract, if the aggregator fails to provide at least 50 percent of the Contract Capacity for three consecutive Operating Months.[20] However, this provision provides little incentive for aggregators to provide consistently good performance over the course of the agreement. Aggregators face no loss for providing poor performance as long as they provide only 50 percent of the Contract Capacity every third consecutive month.

SCE's contract from 2008 to 2012 provided for penalties based on performance at less than 50 percent of the Contract Capacity[21] but the penalties were removed for the

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[18] In 2013, an aggregator who performed poorly in an Event Test in May requested a Re-Test that was not called until August. The performance of the Re-Test was better than the May Test and was then used to recalculate the capacity payment for May, providing a higher payment. The performance of the Re-Test was also applied to June since there were no events in that month. This led to payments based on a capacity that was higher than they were able to demonstrate in those months. PG&E Data Request Response "DemandResponseRFO-2013_DR_DRA_008-Q01-03".

[19] SCE 2013-2014 Agreements; Article 3: Compensation.

[20] SCE 2013-2014 Agreements; Article 10: Events of Default; Termination.

[21] SCE 2008-2012 Contracts; Section 3.4 Delivered Capacity Payment Calculation.

2013 and 2014 agreements.[22] Based on events in May 2013 for which settlements have been prepared, [redacted].[23] However, these aggregators would suffer no real loss as long as they provided greater than 50 percent of the Contract Capacity within three consecutive months. Penalties should be brought back for 2015 to motivate aggregators to provide their Contracted Capacity by May and maintain good performance throughout the term of the agreements.

3. The Commission Should Amend SCE's Agreements To Allow SCE, Not The Seller, To Determine When To Call Seller Directed Tests

SCE's 2013 and 2014 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."[24] This contract term provides the aggregator the opportunity to game the system to demonstrate that they are capable of delivering the Contract Capacity if they have previously performed poorly in Tests or Dispatch Events. However, the ability of the seller to determine when SCE calls the "Seller Directed Test" is not consistent with how actual Dispatch Events or SCE's Tests would be conducted. The foreknowledge of the Test can influence their ability to perform and affect the capacity payment for the month, and subsequent months if there are no other Events dispatched.

Instead, SCE should allow the aggregators to request a Test but the determination of when the Test would occur should be decided by SCE. They could commit to call the test within a reasonable time period of 30 days. SCE allows the same notification outlined in the agreement (Day-of or Day-Ahead) for such a Test as they would in an

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[22] SCE 2013-2014 Agreements; Section 3.3.2 Delivered Capacity Payment Calculation.

[23] SCE Data Request Response "DATA REQUEST SET A.12-09-007-DRA-SCE-002".

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

actual Dispatch Event, providing greater confidence that the aggregator can perform similarly if dispatched at a later date. This would be consistent with PG&E's ability to call an Event Re-Test at their discretion when the Seller requests a Re-Test.[25]

4. The Commission Should Order SCE To Provide Payments Based On Performance In All Hours Of An Event

SCE's 2013 and 2014 agreements determine payments based on the best performing hour of all events in a month, and use that best performing hour going forwards.[26] For example, if they perform at 100 percent of the Contract Capacity for one hour in the month then their capacity payment is based on that best performance and it will not matter if they do not respond at all in all other hours of the month. This method provides a disincentive to perform consistently across all hours and events.

SCE should utilize the best practice method from the 2008 to 2012 contracts in which payments were determined based on performance in all hours of the events.[27] In determining payments going forward when there are no subsequent events called for that location, SCE should use the average performance of the most recent event of the Sub-Load Aggregation Point (SLAP) rather than the best performing hour. This encourages aggregators to provide reliable performance in every hour of every event.

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

SCE's 2013 and 2014 agreements for Day-of products require at least one hour notice to the aggregator.[28] While one hour is the minimum amount of time needed for the agreements to be dispatched according to market conditions, the agreements do not allow for the flexibility to respond to system emergencies. CAISO's System Emergency

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[25] PG&E 2013-2014 Agreements; Section 3.5 Testing.

[26] SCE 2013-2014 Agreements; Section 3.3 Delivered Capacity Payments.

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

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

Operating Procedure No. 4420 calls on available demand response programs requiring 30 minute notification.[29] A change to 30 minute notification would also impact evaluation and modeling of these resources in supply side proceedings, 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.[30] SCE should move to 30 minute Day-of notification, as in PG&E's 2013 and 2014 agreements.[31]

E. The Objectives Of The Staff Proposed Pilots Are Reasonable

Staff makes the following proposals for pilots.

1. IRM2 Enhancement in Northern California (IRM2 Enhancement)
2. IRM2 Implementation in Southern California (IRM2 Implementation)
3. Behavior Programs For Customers On Dynamic Rates (Behavior Programs)

As discussed below, ORA supports the objectives of the staff proposed pilots and makes recommendations and requests for more information for each pilot specifically.

1. The IRM2 Enhancement In Northern California and IRM2 Implementation In Southern California Pilots Should Focus On Enabling Experience In The CAISO Market

The IRM2 Enhancement pilot will focus on enabling third parties to directly participate in the CAISO market, rather than relying on PG&E to provide the needed services, and the IRM2 Implementation pilot will educate third parties on how to bid in to

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

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

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

the CAISO market. The staff proposal lists several activities that will "materially affect what can actually be done in 2015,"[32]

- IRM2 Pilot – PG&E
- Flexible Resource Adequacy Criteria Must Offer Obligation (FRAC-MOO) – CAISO
- Resource Adequacy Flexible Capacity Framework – CPUC
- Rule 24 – CPUC

The proposal does not outline the expected time frame for the resolution of each of these activities and what impact delays in these activities would have on the proposed pilots.

ORA recommends these two pilots should focus on teaching third parties how to directly participate or how to bid in to the CASIO market.

2. IRM2 Enhancement And IRM2 Implementation Should Allow Bidding And Dispatch Of Third Parties in Day Ahead And Real Time Energy And Ancillary Services

Day Ahead and Real Time Energy and Ancillary Services can all deliver value to the CAISO. The main objective of these pilots is to enable direct participation and the bidding of third parties who could potentially provide any of these services. Participants should be allowed to test the bidding of any or all of these services to gain experience with the process of bidding and dispatches to better understand their ability to take part in the CAISO market.

ORA supports this general objective.

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[32] R.13-09-011 Attachment A, p. 1.

3. Behavior Programs For Customers On Dynamic Rates Should Include Optional Stronger Time Of Use (TOU) Rates

The Behavior Programs pilot will test behavior-related strategies to determine whether and which strategies best enable small commercial customers to successfully manage their consumption while on TOU and CPP rates. ORA recommends that this pilot include optional TOU rates that are stronger (more time differentiated) than the mandatory rates. Such options would provide a stronger price signal which supports Objective 1, increasing customer awareness of when peak hours are occurring, and Objective 2, encouraging behavioral change during peak hours to use less energy.

Specifically for PG&E, the mandatory TOU rate is the A-1 rate which has a summer peak and off-peak differential of only $0.03.[33] PG&E also has an optional TOU A-6 rate which has a summer peak and off-peak differential of $0.35.[34] However, this optional rate may be too strongly differentiated to benefit most customers. This pilot should allow PG&E customers to have an option with a differential that falls between the mandatory A-1 rate and the voluntary A-6 rate.

In 2014 and 2015, SCE's customers will be switched to the mandatory Schedule TOU-GS-1 Option A which has a summer peak and off-peak differential of $0.07.[35] Customers can also choose Option B which has a summer peak and off-peak differential of $0.10 but also has high demand charges.[36] This pilot should test a rate option for SCE with a greater differential and without demand charges.

SDG&E's mandatory TOU rate is yet to be resolved in Application 11-10-002. On October 5, 2012, Settling Parties put forth a Motion for the Commission to adopt a Partial Settlement Agreement that includes what they call a mandatory Time of Day

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[33] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_A-1.pdf.

[34] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_A-6.pdf.

[35] https://www.sce.com/NR/sc3/tm2/pdf/ce143-12_2013.pdf.

[36] https://www.sce.com/NR/sc3/tm2/pdf/ce143-12_2013.pdf.

(TOD) rate.[37] Based on what the Commission decides to adopt as SDG&E's mandatory TOU rate, this pilot should offer a rate option with a greater differential.

All three utilities could offer such more highly time-differentiated TOU rates, as "experimental rate schedules" applicable only to pilot project participants and for a limited time frame, following the example of SDG&E's experimental TOU rates for electric vehicle recharging, as proposed, e.g., in SDG&E's Advice Letter 2157-E filed March 26, 2010. In other words, creation of such temporary, experimental rates could be handled through an advice letter process, and could significantly enhance the information that can be gained from pilot studies.

F. More Information Should Be Provided For The Budget Proposed For The IRM2 Pilot For Southern California

The budgets proposed for SDG&E and SCE are $519,600 and $614,300 respectively based on the expenditures needed to replicate PG&E's IRM2 pilot. In comparison, PG&E's budget for IRM2 was $2,458,336. The proposal recommends that the budgets of SDG&E and SCE should ideally be at least 75-80 percent of the budget of PG&E's IRM2 pilot to effectively replicate it.

Given the limited information provided in the proposal, more information is needed to understand how the budgets were developed to determine what funding will be necessary to replicate the IRM2 pilot. Since the budget is based on PG&E's budget for IRM2, information should also be provided on PG&E's current and expected spending to determine if that budget was under or overestimated.

G. More Information Should Be Provided On The Budgets Proposed For The IRM2 Enhanced Pilot And The Dynamic Pricing Pilot

The IRM2 Enhanced pilot has a proposed budget of $2,638,000. It is unclear from the proposal how this budget was determined. Are these costs incremental to funding

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[37] http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M029/K975/29975852.PDF.

already allocated to PG&E's IRM2 pilot and if so, why are they incremental? One budget category is for incentives, how will the pilot determine incentives for participants? Another budget category is for enabling technologies (equipment), wouldn't such equipment already be in place through participation in PG&E's IRM2 pilot?

For the Dynamic Pricing pilot, the proposed budget for all three utilities is $750,000 and can increase to $1 million if automated devices are include in the pilot. It is unclear how this budget was developed and no breakdown is provided for how the spending would be spent. More information is needed to determine whether the proposed budgets of these pilots are appropriate.

H. ORA Does Not Object To Fund Shifting From Demand Response Programs To Fund The Pilots As Long As Existing Programs Are Not Disadvantaged Or Harmed By The Loss Of Funding

Specifically for SCE and SDG&E's pilots, the proposed budgets are:

	IRM2	Dynamic Pricing	Total
SCE	614,300	750,000	1,364,300
SDG&E	519,600	750,000	1,269,600

The Rulemaking suggests funding these programs through potential fund shifting from other demand response programs. ORA is not opposed to using the unspent funds for the pilots as long as the existing program from which the funds are shifted is not disadvantaged or harmed by the loss of funding.

In regards to the proposal to shift funds from SCE's AC Cycling program and SDG&E's 2012-2014 demand response portfolio, it is not clear whether the proposal takes into account the funds necessary to operate the program for the proposed bridge funding year, 2015. For the proposal to shift funds based on savings from changes in the program design of Peak Time Rebate, the savings and shift of funds should be properly tracked and accounted for.

III. CONCLUSION

In summary, ORA expresses support for bridge funding based on recommended program changes and provides concerns and recommendations regarding the program design and funding for the staff proposed pilots. ORA urges the Commission to adopt the suggested changes above to allow greater effectiveness in program and pilot implementation.

Respectfully submitted,

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ATTACHMENT A

Table 1: Evolution of BIP Program Trigger

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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 - 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 - BIP is dispatched just prior to CAISO issuing a Market Notice indicating need to procure available Exceptional Dispatch capacity/energy within its own balancing authority