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)

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) IN RESPONSE TO RULEMAKING 13-09-011

ANN KIM
SHIRLEY A. WOO
MARY A. GANDESBERY

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-2248
Facsimile: (415) 973-5520
E-Mail: saw0@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 21, 2013

TABLE OF CONTENTS

Page

SB_GT&S_0146185

TABLE OF CONTENTS
(continued)

Page

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)

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)
IN RESPONSE TO RULEMAKING 13-09-011

I. INTRODUCTION

Pacific Gas and Electric Company (PG&E) respectfully submits its comments on Rulemaking (R.) 13-09-011, *Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements* (Rulemaking). The Rulemaking's stated intent is 1) to determine how to enhance the ability of demand response (DR) to meet the state's clean energy goals while maintaining grid reliability and 2) prioritizing DR as a utility-procured resource that will be competitively bid into the California Independent System Operator (CAISO) wholesale electricity market. The Commission identifies the following purposes for this proceeding:

1) Review and analyze current DR programs to determine whether and how to bifurcate them into demand-side (customer-focused programs and rates) and supply-side resources (reliable and flexible DR that meets system resource planning and operational requirements);

2) Create an appropriate competitive procurement mechanism for supply-side demand response resources;

3) Determine program approval and funding cycle;

4) Provide guidance for transition years; and

5) Develop and adopt a roadmap with the intent to collaborate and coordinate with other CPUC proceedings and state agencies in order to strategize the future of DR in California.

PG&E looks forward to tackling the issues identified in the Rulemaking. However, there are other equally important issues which must be considered when considering how to advance

DR as a cost-effective resource in the state's loading order. These issues are discussed below, before PG&E provides its responses in Section VII to the questions posed in the Rulemaking.

II. OVERARCHING ISSUES

A. The Rulemaking Must Recognize The Progress Made To Date for DR and Maintain Continuity For The Existing DR Programs

One of the fundamental goals of the Rulemaking is to increase the amount of DR that is integrated with the CAISO wholesale market. PG&E supports this goal, but cautions that the importance and value of existing DR programs must not be ignored. PG&E has a significant slate of DR programs which individual customers and demand response aggregators use to reduce load when called upon to perform. These programs enable many types of customers of all sizes and types to participate in DR. Continuing to get value from these programs and to improve them to make them more viable for more customers is extremely important. The Rulemaking's assumption that bidding DR into the CAISO market would be the best way to capture DR cost effectively could lead to overlooking the value and importance of existing DR programs. Moreover, the prospect of discontinuity in the existing DR market would be harmful if the Rulemaking disrupts the existing programs in favor of new, untested, and vague proposals for bidding into the CAISO market. The Commission must be careful not to compromise or jeopardize what we have accomplished so far with DR at the retail level.[1/]

B. The Actual Need For Fast and Flexible DR Supply Resources Must Be Established And Ways To Improve Other Programs Also Must Be Considered

The Rulemaking assumes that DR resources need to be "fast and flexible" and seeks to turn DR into a fast-responding and flexible wholesale market resource (which the CAISO could control.) PG&E agrees that making some fast-responding, very flexible DR available to the CAISO is a worthwhile goal. At the same time, there are other factors that must be considered. For instance, the magnitude of the need and its timing must be established before deciding if

1/ See attached letter of DR Collaborative to the Commission.

existing DR programs must undergo fundamental changes to become supply-side resources. For PG&E, that determination of need and timing occurs in the Long Term Procurement Plan (LTPP) proceedings. As of this date, the need for additional "fast and flexible" resources for PG&E is in the distant future. The September 16, 2013 ruling in the LTPP canceled the track determining flexible needs, noting there was some indication that the system flexible needs may be low or non-existent depending on the resource additions made to meet local reliability needs in Southern California. The ruling further indicated the determination of flexible system needs would be in scope for the next LTPP scheduled to start in 2014. (R.12-03-014, Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 And Track 4 Schedules, pp. 6 to 7. September 16, 2013.)

In addition, the Commission must remember that demand response programs rely on the willingness and ability of customers to participate, whether the DR is characterized as demand-side or supply-side. Responding very quickly and very flexibly to DR event notifications may work for some customers, but not be feasible for many others. Nevertheless, customers who cannot or do not wish to provide load reductions on that basis still may be willing to participate in other types of DR programs. Therefore the Rulemaking should not focus exclusively on DR programs that would be bid into the CAISO wholesale market, but should also address other DR programs and the key barriers to the improvement and growth of these programs for customers whose load cannot be reduced as quickly and flexibly as the Rulemaking and CAISO envision.

C. The Commission Must Not Make Unsupported Assumptions or Ignore Pivotal Questions. An Evidentiary Record Is Needed.

The Rulemaking makes critical assumptions that are unsupported by any evidence, while also ignoring other basic issues which must be addressed as part of making any fundamental changes in the utilities' DR programs. For instance, the Rulemaking assumes that fast and flexible DR is needed, but it does not define any attributes for what "fast" and "flexible" mean. Nor does the Rulemaking reference any evidence as to when this type of DR would be needed.[2/]

Another example of a key DR issue that the Rulemaking ignores is cost-effectiveness. Cost effectiveness methodology and the inputs needed to evaluate the cost-effectiveness of utility DR programs are critical to testing whether DR provides sufficient value in comparison to its cost to customers. The Rulemaking, however, is silent on whether and how this critical analysis will be performed for DR that is bid and integrated into the CAISO wholesale market. Similarly, the Rulemaking ignores the need to resolve questions about cost effectiveness inputs for existing programs for the next program cycle.

The need to identify all critical issues and develop an evidentiary record, including evidentiary hearings as appropriate, is fundamental to the Commission's process of arriving at a sound decision, and should not be given short shrift here.

III. THE USE OF PILOTS

There may well be significant new opportunities for supply–side ("wholesale") DR to convey benefits to customers and the electrical grid just as existing demand–side ("retail") DR currently conveys benefits.[3/] However, creating the opportunities does not ensure that DR market participants will use them, or that they will be cost effective. Further exploration is required around the real value of these DR-related benefits, as well as the ability and willingness of DR market participants (including customers and DRPs) to unlock them. This exploration should happen prior to any investment of significant time and resources in the development of commercial programs and infrastructure designed to enable these benefit streams. For this reason, PG&E supports the Commission Staff's general approach to pilots in the Rulemaking.

2/ The requirements for "flexible" DR will be developed in Phase 3 of R.11-10-023 and the CAISO's Flexible Resource Adequacy Criteria and Must-Offer Obligation (FRAC MOO) stakeholder process. There is no effort currently underway to define "fast" and "flexible" DR, so this fundamental question would need to be taken up in the Rulemaking.

3/ A detailed comparison of these two ways of capturing DR value was presented at the October 16, 2013 DR workshop by PG&E (attached).

PG&E recommends the timely implementation of a focused set of pilots to validate the potential benefits of supply-side DR, along with work to identify and resolve cost-effectiveness methodology and inputs for wholesale DR. A regulatory decision on whether to pursue full-scale implementation would follow. PG&E's IRM2 Pilot is a good example of this approach and is already slated to evaluate how to integrate DR with the CAISO energy markets. The IRM2 Pilot also contemplates an expansion to more advanced resource types, including ones that provide the CAISO with greater flexibility for renewable integration[4/]. Once it has been conclusively determined that there is a sufficient interest and value in a particular pilot to warrant creating a full-scale, cost-effective program, the IOUs can create a full-scale DR program.

During this process, the continuity of the current portfolio of IOU programs must not be compromised. PG&E proposes that the Commission (1) approve a bridge-year funding for 2015, (2) allow the IOUs to file an application in January 2015 to continue their retail programs, and (3) implement a process in which the DR market players have the ability to adapt to Commission's Decisions in a timely and cost-effective manner that supports the evolution of DR.[5/] In the meantime, pilot programs oriented to the wholesale market can be implemented and scaled up if and when it is appropriate.

In the future, as "supply-side" pilots validate various benefit streams, the DR cost-effectiveness methodology should be updated to reflect these values. Doing so will enable the utilities to incorporate relevant concepts of these pilots and realize the value for the IOU DR programs (e.g., add a program that meets flexible RA requirements).

IV. ADDITIONAL SCOPING ISSUES

A. What is the Auction Mentioned by the CAISO and in the Rulemaking

At page 13, the Rulemaking mentions that the CAISO and the Commission have been

---

4/ See, PG&E slides from the October 16, 2013 DR workshop on IRM2 pilot for details on how these efforts will advance DR (attached).

5/ The IOUs' next application would presumably be for 2016 through 2018, pending a reassessment by the Commission as the Track 3 issues are resolved.

working on establishing a Joint Reliability Multi-year Framework which aims to "1)create two and three-year-ahead Resource Adequacy requirements, 2) develop a CAISO-run residual backstop auction, which will provide a platform for Load Serving Entities to procure capacity to fill Resource Adequacy obligations not met in the bilateral market . . . ". In its October 14, 2013 PHC statement, the CAISO proposed that the Commission develop rules for entities under Commission jurisdiction to participate in a voluntary auction for DR for the 2015 RA year. (CAISO PHC Statement, p. 2) At the Commission's October 16, 2013 workshop, John Goodin from the CAISO stated that 2015 would be a pilot year with one standard product, with expansion to other products occurring in later year. Mr. Goodin stated that the CAISO would run the auction, where buyers and sellers could find each other and establish mutually acceptable prices. So far, however, these vague statements provide scant information about the auction, and do not address how this auction where "buyers and sellers find each other" leads to DR being integrated into the wholesale market. PG&E notes that Rule 24, in Advice Letters 4298-E, 2949-E and 2526-E, establish the procedures for third-party and utility demand response providers to bid bundled load into the CAISO wholesale market,[6/] That bidding process will occur through submission of resource registrations in the CAISO Demand Response System (DRS).[7/] PG&E is informed and believes that DR services contracted through the proposed auction would still be subject to the Rule 24 and CAISO bidding processes—presumably regardless of the identity of the contracting parties. These are just pieces of the puzzle. No real information is available yet on basic questions, such as:

6/ To view Advice Letter 4298-E, et. seq. go to http://www.pge.com/tariffs/ and click on Advice Letter Index from the list, then click on the box for 2013 for Electric, then scroll down and find the advice letter. In the alternative, you can click on this hyperlink: http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4298-E.pdf

7/ A high-level description of the resource registration process can be found in footnote 6 of the *Joint Petition Of Pacific Gas And Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, Division Of Ratepayer Advocates, Enernoc, Inc., Johnson Controls, Inc., Comverge, Inc., Alliance For Retail Energy Markets, And Direct Access Customer Coalition For Modification Of Decision 12-11-025 Ordering Paragraphs 7, 12, And 21,* Filed in R.07-01-041, August 9, 2013.

1. How will this auction work? The CAISO has provided no details regarding the design and operation of this proposed market. At the workshop, the CAISO stated this auction would work like eBay; however, it is unclear why the CAISO believes a descending-clock auction for non-standard products is the appropriate mechanism for DR programs.

2. Why does the CAISO need to run it instead of the Commission? Is an auction even necessary in the first place? What is it designed to achieve?

3. How would the auction lead to results that integrate resources into the wholesale market. (i.e. Could it lead to resources for which bids are never actually accepted by the CAISO?) Could it lead to resources for which the payments by the CAISO for the resource would be less than what the buyer under the contract pays the seller?

4. How would the auction integrate with Rule 24 and the CAISO's market processes and DRS?

5. How does the CAISO propose to pay for the development and operation of such an auction? Any costs incurred by the CAISO and rates for the services provided by the CAISO are subject to approval by the Federal Energy Regulatory Commission. Is it correct that the design and operation would also be subject to FERC modification and approval?

6. How will this DR auction interface with existing procurement mechanisms, particularly the resource adequacy proceeding as it is being modified? The CAISO has stated it would run this action in 2014 for a 2015 RA showing, but has provided no details about the timing or interaction with those processes.

7. How will this DR auction interface with proposed changes in procurement mechanisms, including the Joint Reliability Framework which will not be put in place until later? The CAISO has stated that this auction is intended to be complementary, but has not explained how or why this mechanism would not be duplicative of its proposed reliability services auction.

B. Improvements to the DR Cost Effectiveness Methodology

Changes to the DR cost-effectiveness methodology are essential to ensuring that robust programs are developed in the next DR program cycle and for programs to be bid into the CAISO wholesale market. Decision (D.) 12-04-045 highlighted the need for revisions to the DR cost effectiveness methodology.[8/] In the October 19, 2012 workshop on DR cost effectiveness,

---

8/ "Correcting the deficiencies will improve the Protocols for the future. We describe these deficiencies below and direct Commission Staff to hold workshops to address and develop cures for the deficiencies," D.12-04-045, p.45.

participants agreed that the following cost effectiveness issues must be considered in the next DR rulemaking and how they could be resolved: 1) the methodology for calculating the A-factor, 2) the treatment of dual participation, 3) whether a portfolio- versus program-level cost effectiveness, and 4) identifying how non-program-specific costs should be addressed. No progress on this issue has been made since the October 19, 2012 DR cost effectiveness workshop, so the Commission should move forward and resolve these outstanding issues before the utilities must develop their next DR program applications. In addition, the Commission must address the issue of cost effectiveness for wholesale DR programs

C. Better Integrating Demand-side DR Programs into Wholesale Market

The wholesale market focus of the Rulemaking misses the question of what more can be done to ensure that the CAISO integrates the utilities' demand–side DR programs into their operational load forecasts. The utilities have already made a great effort to enable the CAISO to better capture the benefits provided by the retail DR programs: most of the utilities' DR programs are dispatchable by sub-Load Aggregation Point (subLAP) or Local Capacity Area (LCA), and each utility provides the CAISO and the Energy Division with daily reports on the amount of DR scheduled to be dispatched (including location) and what more is available to be dispatched. Yet despite these efforts, it appears that the CAISO still does not fully value these programs in its operational and planning forecasts. If there are steps that the CAISO can take to better integrate DR that is not bid into the wholesale market into its operations and thus avoid double procurement of energy resources, these steps should be identified and explored. Better integration of retail DR programs into the CAISO's market operations will improve their utility to the CAISO and thus increase their value, a goal which all parties should support.

D. Commission Guidance on the Utilities' Next DR Applications

The Commission must promptly provide explicit guidance to the utilities about when and how they should submit their next DR program applications. Assuming that the Commission will authorize a one-year bridge period, this guidance should be given no later than June 2014 to allow the utilities time to develop their respective applications and file by January 2015, in a manner consistent with the discussion below on creating three tracks for this proceeding.

E. PG&E's 2012 DR Program Performance

PG&E's 2012 DR programs should be assessed as SCE's and SDG&E's were before the Commission makes any conclusions about the effectiveness of current DR programs. The general assessment of the capability of utility DR programs in the Rulemaking appears to have been, to a large degree, influenced by the report developed by Commission staff (Staff) entitled, *Lessons Learned from the Summer 2012 Southern California Investor-Owned Utilities' Demand Response Programs May 1, 2013* (Report) in proceeding A.12-12-016 et al. PG&E notes that the Report did not include PG&E's DR programs within its scope, so it would be inappropriate for the Commission to make any judgments or conclusions that will impact all utilities based on the Report. The Commission should develop a full evidentiary record to support its findings and orders with respect to PG&E and not just rely on the Report.

V. ISSUES THAT MAY REQUIRE AN EVIDENTIARY RECORD

In the September 19, 2013 Order Instituting Rulemaking (OIR) and at the October 16, 2013 workshop on supply-side DR, it was apparent that many parties are making unsupported assumptions about DR that must be addressed. So, before the Commission directs the utilities to devote significant time and resources to develop new "flexible" DR programs to bid into the wholesale market or move existing programs into the wholesale market, it should first build an evidentiary record to inform the following key issues:

A. The Need and definition for Flexible DR.

The Rulemaking appears to have pre-determined that "fast and flexible DR" is necessary. There may be a need for DR with these attributes at some point, but if that need is not immediate, there is no need to rush the process by which DR resources with these attributes, once they are defined, are developed. Given the recent ruling9/ in R.12-03-014 cancelling Track

9/ R.12-03-014, *Assigned Commissioner and Administrative Law Judge's Ruling Regarding Track 2 and Track 4 Schedules*, issued September 16, 2013.

2 of the 2012 Long-Term Procurement Plan (LTPP) proceeding which focused on system flexibility issues, it is not clear what need exists for flexible DR. In addition, no need has yet been demonstrated for fast DR. If a need is found, the Commission should explore the least-cost way of addressing that need, which may include using retail DR programs.

The Commission must also define "fast" and "flexible" attributes, and then determine when these types of DR are needed. The requirements for "flexible" DR will be developed in Phase 3 of R.11-10-023 and the CAISO's Flexible Resource Adequacy Criteria and Must-Offer Obligation (FRAC MOO) stakeholder process. There is no effort currently underway to define "fast" DR so this will need to be taken up in the Rulemaking.

B. The Proposed CAISO Auction.

The proposed auction mentioned by the CAISO and the rulemaking must be fleshed out and addressed in detail, with actual information and evidence. At a minimum, the questions and issues identified in Section IV. A. above must be addressed and answered based on record evidence.

C. The value of transitioning existing DR programs to supply-side resources.

Transitioning existing DR programs into supply-side resources must provide clear ratepayer benefits that justify the costs. Absent clear definition from the Commission, PG&E assumes "supply-side" to mean bidding in DR as PDR or RDRR (i.e. Wholesale" DR). If this is the Commission's intent, PG&E has strong concerns about taking these steps. PG&E's existing DR programs are cost effective, valuable resources. Transitioning them into supply-side resources, presumably by requiring that they be bid into the wholesale market, would risk increasing costs, and confusing participating customers, leading to reduced participation. Transitioning existing DR programs into supply-side resources should serve a clear purpose that is supported by evidence, and provide higher net benefits to ratepayers. Therefore the Rulemaking should first establish the benefits of transitioning existing DR programs to supply-side resources as well as the criteria that would need to be met to support such a transition.

D. Reliability of supply-side DR versus demand-side DR.

At the October 16 workshop, some parties made the statement that supply-side DR will somehow be more reliable than demand-side DR and on this basis, more supply-side DR is necessary. There is no evidence yet to support this assumption. So if this is one reason for developing more wholesale DR, the Commission should compare the reliability of PG&E's Proxy Demand Resources (PDR) that have been bid and dispatched into the CAISO market to the reliability of the utilities' comparable retail DR programs.

E. The Necessity to Support Financing DR.

Before the Commission develops a mechanism to support financing for DR projects, it should determine that doing so would address an actual barrier. In the OIR, the Commission states that it should explore the need for credit enhancements to finance DR infrastructure. (OIR, p. 19, item 13.) Credit enhancements were approved by the Commission for energy efficiency projects in D.13-09-004 to address what the Commission has identified as barriers to financing energy efficiency improvements. (D.13-09-044, p. 2.) The proceeding in which D.13-09-044 was adopted did not address or explore whether there are any barriers to installing DR infrastructure and, if so, whether on-bill repayment (OBR) would help reduce barriers to DR financing. Given the complete lack of record on that issue, the Rulemaking should address whether in fact there are barriers to financing DR infrastructure, an issue which to PG&E's knowledge has not been raised in prior DR proceedings. Only if there is a finding of a barrier, should the Commission address whether financing would be appropriate to address that barrier, and whether and to what extent limited credit enhancements could help address such a barrier. To the extent that financing is discussed, the Rulemaking should also address the appropriate funding source for DR financing and the impact of providing credit enhancements on DR portfolio cost-effectiveness. If the Commission finds that OBR would help to remove a barrier, then PG&E recommends that it be addressed in a separate track of the Rulemaking due to the complexity of the issue.

VI. PROPOSED PROCEDURAL SCHEDULE

The issues within the preliminary scope of the Rulemaking are numerous and many are very complex. PG&E recommends that they be organized into three separate tracks to ensure that the most time-critical issues are addressed first. Creating three tracks will provide customers and other DR stakeholders the certainty and stability needed to continue to grow and enhance a cost-effective DR portfolio while advancing DR as a resource. PG&E provides a recommended breakdown of the three tracks and associated timeline.

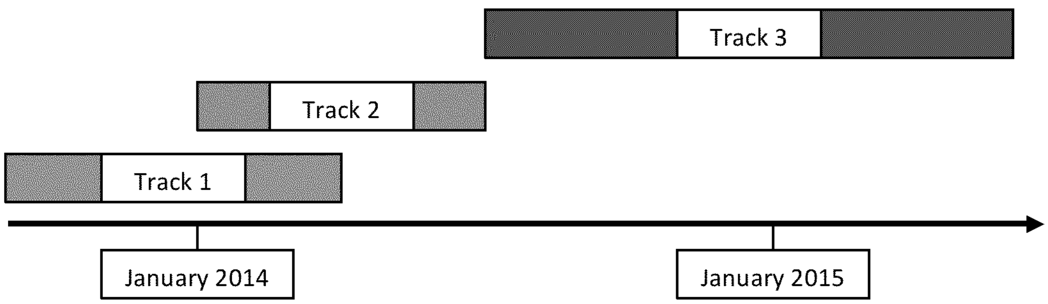
Track 1 would focus on the issues associated with the bridge period for the IOUs' DR programs. In a letter dated September 18, 2013, the Commission's Executive Director granted the IOUs' request to extend the filing date for the next DR application to July 31, 2014. In the OIR, the Commission proposed a bridge funding decision by Q2 2014. PG&E is concerned a decision so late in 2014 would come too close to the July 31, 2014 deadline and also distract from other more complex issues within the scope of the Rulemaking. The bridge funding issues will not be numerous or overly complex, so a bridge period decision should be possible by late Q1 2014.

Track 2 would focus on the issues needing to be resolved in order for the IOUs to develop and file their next program applications, including Commission guidance for these applications. Track 2 issues would include 1) changes to the DR cost-effectiveness methodology and associated template, 2) Commission guidance on the utilities' next DR program applications, 3) changes to dual participation rules, and 4) an assessment of PG&E's 2012 DR program performance. The utilities' next application would presumably be for the 2016 – 2018 period, pending a reassessment by the Commission as the Track 3 issues are resolved. Under this approach, the utilities would need a Commission decision on Track 2 issues by June 2014 so the utilities can submit their applications by January 2015.

Track 3 would consist of all of the original 14 issues identified in the September 19, 2013 OIR as well as any other issues proposed by parties pertaining to wholesale DR that the Commission chooses to add to the scope of the Rulemaking. Because there would be so many issues in Track 3, the Commission could address them in groups and issue multiple decisions on them. When these issues are decided, the utilities' DR programs could be revised to conform to these decisions.

The three tracks could be taken up sequentially or in a staggered manner. PG&E recommends a procedural schedule for Track 1 and provides a simple Gantt chart for the three tracks.

Action	Time
PHC Statements Due	October 14, 2013
Comments on 9/19/13 OIR	October 21, 2013
Pre-hearing Conference	October 24, 2013
Ruling for additional questions and draft scoping ruling	November 29, 2013
Responses due to November 29 ruling	December 13, 2013
Final scoping memo	~January 15, 2014
Proposed decision on Bridge Period	~February 1, 2014
Final Bridge Period decision	~March 3, 2014



VII. PG&E'S RESPONSES TO THE QUESTIONS PRESENTED IN THE RULEMAKING

PG&E submits the following responses to the six question presented on pages 22 to 23 of the Rulemaking. These responses are based on information currently available to PG&E.

A. Question 1: Do you find it reasonable for the Commission to authorize SCE, SDG&E, and PG&E a one-year bridge funding to allow current demand response programs to continue, as is, through 2015 while the Commission contemplates changes to the structure of the overall demand response program?

PG&E supports a bridge-funding period to allow time for the Commission to address the issues in this proceeding while ensuring stability in the current programs. However, there are some key issues that must be addressed in a bridge-period decision. PG&E requests the following provisions in the bridge-funding decision:

- **Budget and Cost Recovery:** PG&E requests cost recovery for a 2015 DR program budget that is equal to the 2014 DR program budget, including pilot programs. PG&E's 2015 budget may need to be augmented by $2.9 million, which is the amount associated with the associated employee benefits burden for DR that historically has been authorized in the General Rate Case, if the Commission approves a partial settlement agreement among PG&E, the Utility Reform Network, and the Marin Energy Authority filed September 6, 2013 in A.12-11-009 and I.13-03-007. The proposed settlement would increase PG&E's recovery in rates for DR in an amount sufficient to fund employee benefits and burdens for those PG&E employees who work on DR programs, rather than recovering those amounts in the GRC. Maintaining the same level of funding as authorized for 2014 plus the associated benefits burden will ensure that existing programs continue through the bridge period uninterrupted.

  If a bridge period is authorized, it should be treated as a fourth year of the current program cycle, rather than as a stand-alone year. Unspent funds in the current portfolio cycle should continue to be available for use by the utilities in 2015 and any unspent funds should be used to offset the revenue requirements for program years 2016 and beyond. This is appropriate due to the late start on many of PG&E's DR programs from the delay in issuing the 2012-2014 program budget decision, and delays in Energy Division approval of PG&E's pilot programs which have held up program implementation. To the greatest extent possible, pilots should be extended into 2015 and participation would thus be expanded to take advantage of the additional year.

- **Budget Flexibility:** With the many issues to consider during this proceeding, PG&E requests budget flexibility to make it easier to validate various concepts and evaluate potential benefit streams. As such, all fund-shifting rules should be eliminated with the exception of those governing the Special Projects category, which includes DR-HAN Integration and the Permanent Load Shifting (PLS) program. The Commission prohibits fund shifting within the Special Products category and fund shifting from Special Projects to other budget categories.[10/] In D.12-04-045, the Commission argued that this restriction will allow them "to properly monitor pilots and special projects to determine their efficacy and viability as a future full time program".[11/] PG&E agrees with this statement for special projects, but given the Commission's desire to expand the DR Pilots and the impact of moving the benefits burdens from the GRC to the DR revenue requirement, PG&E believes that the fund shifting rules should be relaxed. In fact, greater flexibility should be afforded to better facilitate the DR Pilots should the utilities decide to expand the scope of their DR Pilots.
- **Intermittent Renewables Management 2 Pilot (IRM2):** PG&E would like authorization to record incentive payments for this program in its two-way balancing account within the Demand Response Expense Balancing Account (DREBA). This pilot program represents a high priority for PG&E because it provides third-party DRPs an opportunity to gain experience participating in the wholesale energy market with limited financial and business risk. Having the flexibility to record incentive payments in the two-way account rather than being constrained by a defined incentive budget will allow PG&E the flexibility to work with any DRP interested in participating.
- **Aggregator Managed Portfolio (AMP) Program:** PG&E requests authorization to extend

---

10/ D.12-04-045 Ordering Paragraph (OP) 4.

11/ D.12-04-045, Discussion on p. 28.

its current AMP contracts through the bridge period. The AMP program provides a significant amount of cost-effective DR and ensures the continued engagement of the associated third-party DRPs. This is a critical part of providing aggregators and customers the certainty needed to maintain these important resources. This extension should not include new features (i.e. fast, flexible, PDR, etc.) that will take more time to fully define and evaluate.

- **Cost Effectiveness:** PG&E requests that no cost effectiveness test be required for 2015. The cost effectiveness of PG&E's 2012-2014 DR programs has already been litigated. Accordingly, any extension of these programs should be based on the Commission's original finding that they are sufficiently cost effective to be approved. PG&E requests that the Commission address the cost effectiveness issues affecting the retail DR programs in time for the utilities' next applications.

B. Question 2: Do you support the objectives of the staff proposed pilots? Please provide alternative suggestions for Utility pilots in 2015 if you do not.

Pilot Proposal for IRM2 Enhancement in Northern California: PG&E supports the continuation of PG&E's Intermittent Renewables Management 2 (IRM 2) Pilot Program. However, as described in the OIR, the changes proposed would appear to simply amount to a capacity payment to Marin Energy Authority (MEA) or any Energy Service Provider (ESP) for any wholesale DR it can provide. By not requiring MEA or other ESPs to use PG&E's infrastructure, PG&E will have no way to confirm that MEA is bidding in a manner consistent with the requirements of the pilot.

That said, the added year will provide PG&E the opportunity to put into action the lessons learned during the 2012-2014 phase of the current version of the pilot, and provide valuable experience for customers, aggregators, technology vendors, energy service providers, community choice aggregators and the CAISO in working with wholesale DR. In addition, PG&E would like to add the objective of demonstrating DR services that would help during periods of over-generation (i.e., load-increasing DR) of intermittent renewable resources. To meet this objective, PG&E would instruct customers to consume more energy when certain CAISO market triggers (to be determined) indicating over-generation are met.

Pilot Proposal for Behavior Programs for Customers on Dynamic Rates: As a general statement, the description of the proposed pilot program will need to be clarified to ensure that the goals and objectives are met. Because PG&E has already transitioned a substantial number of its small and medium business (SMB) customers to default time-of-use (TOU) rates, the Commission should clarify whether the pilot programs in the OIR are applicable to SMB customers transitioning to PDP on a default, opt-out basis, (beginning in November 2014 for PG&E) or to customers on TOU or PDP.

Goal/Objective 1: PG&E is supportive of Goal and Objective 1. PG&E is currently working toward this goal and objective as part of the implementation of its TOU and CPP rates. The CPP rates include the SmartRate program for residential customers and Peak Day Pricing (PDP) for commercial and industrial (C&I) customers. PG&E has established metrics and a reporting process to track customer understanding of these programs. (See, D.10-02-032, OP 15.) Additionally, in the 2014 GRC I, PG&E asked for funding for maintenance of PDP customers to support them after they have transitioned to their new dynamic rate as well as the awareness efforts of this transitioned group that are specifically tied to the established metrics noted above.[12/] Any additional funding approved by the Commission in the Bridge Funding Decision could be used to build on existing or add new pilots to discover other ways to help customers who have transitioned to PDP. However, the $750,000 proposed budget would not be sufficient to conduct a meaningful pilot program and study.

Goal/Objective 2: PG&E is supportive of Goal and Objective 2. PG&E is currently implementing a two-phase pilot program to test how provision of information as a service will

12/ The extension of previously authorized funding for outreach and education of small and medium business customers during their initial default to TOU and CPP has been requested in a Petition to Modify D.12-02-032 and D.11-11-008, filed on or about March 13, 2013 in A.09-09-022.

impact awareness of, and selection of PDP rates for SMB customers subject to the November 2014 default date. Phase 1 of the pilot will begin in Q4 of 2013 and is expected to conclude in Q1 of 2014. In Phase 1, PG&E plans to send customized, informational emails to 20,000 – 28,000 SMB customers to invite them to make a decision related to participating in PDP (enroll/opt out). These customized emails will frame the PDP program in terms of the customer's energy costs and introduce program concepts including bill protection, event days, charges and credits and curtailment benefits. Phase 1 will test whether a customized email campaign helps build awareness of the PDP transition and is able to lead customers to a decision regarding their participation in PDP; specifically whether to enroll earlier than November 2014 or opt out of the impending transition. Phase 2 (Q1 2014) of the pilot will support those customers who choose early enrollment in PDP and will experience their first events in the 2014 season. Phase 2 will test whether customized pre-event day information, event-day tips and post-event day feedback delivered via email can provide greater program engagement and communicate cumulative success for the customer and greater load shed for PG&E. PG&E will use participating customers' 15-minute interval meter data to provide them with a pre-event day email showing the predicted load curve, PDP costs and potential savings from curtailment along with recommended curtailment strategies to employ. Post-event feedback will demonstrate results in both load and costs. This pilot is currently being funded through the Dynamic Pricing budget. The results of the pilot and available funds will help inform communication strategies for those customers who will be transitioned to PDP in November 2014 and experience their first PDP season beginning May 1, 2015.

Goal/Objective 3: PG&E is supportive of Goal and Objective 3. In 2012, PG&E initiated the mandatory default to TOU rates of those SMB customers (C&I customers with a peak electric demand of less than 200 kW) with at least 12 months of interval data. In November 2013, the second wave of SMB customers will transition to TOU rates; in November 2014, the remaining

SMB customers will make the transition. Starting in November 2014, SMB customers that have been on a TOU rate for at least two years will be defaulted onto the PDP program.

PG&E has identified a need to develop enabling technologies for this group of SMB customers that will move to PDP in order to help them participate in PDP by capturing the benefits that were intended with the dynamic pricing programs. In 2013, PG&E started developing an emerging technologies assessment to test advanced programmable controllable thermostats (PCT) that are designed specifically for SMB customers that will improve their ability to respond to a PDP event. The objectives of this emerging technologies assessment are:

- Identify if SMB customers will find this technology useful in operational efficiency, energy savings and DR;
- Demonstrate that a mid-stream channel (e.g., HVAC contractors) can be a successful way to introduce DR enabling technologies to SMB customers;
- Help SMB customers adapt to TOU and PDP rates by providing a tool that better manages their HVAC energy use; and
- Evaluate if the two-way communicating PCT can provide energy efficiency (EE) and DR benefits, and measure the associated load impact and energy savings.

PG&E will continue to provide updates on this DR emerging technologies assessment to the Commission in the semi-annual Demand Response Emerging Technologies Report and the Peak Day Pricing Semi-Annual Education and Outreach Assessment Report.

C. Question 3: In Section II.C.4 of the staff proposal, Energy Division staff recommends that SCE and SDG&E will both need budgets that are 75-80 percent of PG&E's current IRM2 budget ($2.458 million) to be able to effectively replicate the IRM2 pilot in their territories. Do you agree with that assessment? If not, what would be an appropriate budget for SCE and SDG&E to replicate the IRM2 pilot in their territories? Are there ways to modify the allocation of specific costs of the pilot such that SDG&E and SCE will not need as much as 75-80 percent of PG&E's budget?

PG&E is unable to accurately assess the staff proposed budget for SCE and SDG&E.

D. Question 4: Do you agree with the proposed budgets for the other pilots in the attached staff proposal?

PG&E supports the proposed program budget for the Pilot Program for Behavior Programs for Customers on Dynamic Rates. The objectives will probably require both a process evaluation and a load impact evaluation, so if the intention of the pilot is to support customers on

PDP in summer 2015 then PG&E will need to access the budget by Q2 2014. This will allow enough lead time to conduct an RFP, select a consultant, and set up the control experiment(s) adequately before the November 2014 default in order to evaluate different methods of communication and customer behavior in the 2015 event season. The specific budget required to implement any pilot will be largely dependent on the size and complexity of the specific pilot. The Rulemaking states that the pilot budgets would exclude any technology or evaluation. (Rulemaking, Attachment A, p.15) PG&E requests clarification on how these aspects of the pilot budgets would be funded, since EM&V is expected to cost up to $450,000.[13/]

As a separate matter, Goal and Objective 3 are being addressed through the DR ET Pilot Program in 2014. Based on the results of this pilot, PG&E plans to roll out this technology to all of its SMB customers using Auto DR program funding in 2015 and beyond. In the event that the CPUC approves Auto DR funding for the bridge year(s), there is no separate funding required for Goal/Objective 3 so that the proposed pilot program budget could be directed to meeting Goal/Objective 1 and Goal/Objective 2.

E. Question 5: In D.13-04-017, the Commission authorized SCE to shift $8.7 million in unspent funds from its Air Conditioner (AC) Cycling Program to fund various improvements to its Demand Response portfolio. It is Energy Division's understanding that SCE has approximately $8 million in unspent funds in its AC Cycling Program. Do you support shifting remaining unspent funds from SCE's AC Cycling Program to support the pilots described in the staff proposal? The same decision authorized SDG&E to shift $1.7 million from its 2012-2014 demand response portfolio to fund various improvements to its Demand Response programs. Do you support additional fund shifting from SDG&E's 2012-2014 demand response portfolio to fund the pilots described in the staff proposal?

PG&E respectfully declines to respond to this question because it appears to be directed only to Southern California Edison Company and San Diego Gas & Electric Company.

13/ Attachment A, Staff Proposals, of the Rulemaking, states at page 15, under New Pilot Budgets for 2015, "Minimum budget of $500,000 per utility, but that would exclude using any kind of technology or evaluation." Consequently the budget authorized needs to be increased to cover evaluation and measurement work for the pilots in the Staff Proposals for behavior programs involving dynamic rates.

F. Question 6: In D.13-07-003, the Commission directed SCE and SDG&E to transition their Peak Time Rebate (PTR) programs to be an opt-in program (in order for participants to be paid a monetary incentive for load reductions) by May 2014. This transition will enable both utilities to save significant incentive funds for the program. Energy Division's May 1 2013 DR Lessons Learned Report estimated that SDG&E paid $10.1 million in 2012 PTR incentives to its residential customers, yet 94 percent of the incentives paid yielded no significant load reductions. SCE paid $27 million in 2012 PTR incentives, and 95 percent of incentives were paid to customers who were not expected to or did not reduce load significantly. Do you support the Commission using the expected savings from the PTR program incentives to fund the pilot activities described in the staff proposal?

PG&E does not currently have a PTR program, but it does not support the Commission staff's idea of using the "expected savings" from the PTR program incentives to fund the pilot activities described in the staff proposal. The PTR incentive is not funded by its own revenue requirement. Therefore, there is no authorized incentive amount being collected in rates that can be used to fund other activities. In essence, the premise of the question is incorrect in assuming that reducing PTR incentives will result in program budget savings that could be used to fund the proposal pilot programs. Moreover, PTR has not been authorized for PG&E in either a default or opt-in form.

The PTR incentive consists of an electric rate discount that applies to participants when they reduce their usage below a defined customer-specific reference level (CRL) during operating hours on event days. The CRL is calculated based on the average of the highest usage on a specified number of previous days prior to the event. PTR credits are earned to the extent the customer's usage is less than the applicable CRL during a specific PTR event. However, it does not matter whether the lower usage 1) simply comes from the customer's normal activities, or 2) results from the customer affirmatively reducing usage below what it would have been in respond to the price signal.

When the customer's usage is below its CRL with normal activities, the customer's PTR incentive is a structural benefit, i.e. it results from the structure of the PTR program, without any customer response. This creates a shortfall in the utility's collection of generation revenue because these incentives resulted in lower revenue accruing to the generation balancing accounts.

Through the normal function of generation balancing accounts, this undercollection would be paid by customers through increased rates in the following year. Therefore, if an opt-in PTR program is created, it may result in a smaller undercollection, but in no way results in a surplus of revenue that can be used for other purposes.

Although PG&E made its PTR proposal in the 2010 Rate Design Window proceeding (A.10-02-028), PTR has not been approved for PG&E yet. PG&E has urged that PTR should await the results of the full rollout to SDG&E's customers as well as the Commission's determination on a long-term vision for residential rates in A.10-02-028.[14/] PG&E is still waiting for a proposed decision in this proceeding, which may or may not approve PTR for PG&E.

Question 6 mistakenly assumes that when PTR for SCE and SDG&E customers becomes an opt-in program, instead of a default mandatory program, customers who produce no significant load reductions in response to PTR would not opt in and the incentives they would have received will be saved. PG&E calls PTR customers that do <u>not</u> reduce load during a PTR event "structural savers" and the incentives paid to them "structural savings" because the customers benefit from PTR without actually responding to the pricing signal.

When PTR is an opt-in program, there is nothing to stop structural savers from opting in. Opting in would be especially attractive to structural savers because PTR provides a potential benefit through the incentive, without any risk of an increase in the participating customer's bill if the customer does not respond to the PTR price signal because the PTR rate is designed to be revenue neutral. Regardless of whether PTR is opt-in or default opt-out, there will still be structural savers and structural savings. However, although as noted above, under an opt-in structure they may be fewer and lower than under opt-out PTR.

When PTR incentives for structural savings are paid to structural savers, PG&E does not experience a cost reduction and would instead experience a revenue undercollection (that is, revenue collected is less than cost) in the generation balancing account. As a result rates would

14/ See, A.10-02-028, PG&E Reply Brief, filed June 7, 2012.

be increased in the following year to collect the undercollection. PG&E's testimony in A.10-02-028, (Exhibit PG&E-1, page 2-5, lines 11 to 18) explains how PTR incentives, or bill savings, are handled:

> The credits [PTR incentives] provided to customers will be reflected as reductions to generation charges. Typically, generation revenue is applied to the generation balancing accounts where revenue and cost (or adopted revenue requirement) are compared. Under- or over-collections in these accounts would then be recovered or returned to customers by adjusting generation rates paid by all bundled customers in the following year. PG&E proposes this same treatment for variation in generation revenues and costs that result from demand response efforts undertake in response to PTR events.

In the next paragraph of its testimony, PG&E maintains that such undercollections should be collected only from residential customers.

> Bill savings attributable to structural savings, however, do not generate real cost savings. If managed in the existing system of generation balancing accounts, the cost of bill savings attributable to structural benefit would result in a generation undercollection and be paid by all bundled customers. These costs [structural savings] are more appropriately allocated only to the residential customer class where the PTR program is offered. To remedy this potential inequity, PG&E proposes that the portion of the credit provided to customers representing structural savings be allocated directly to the residential class in the generation component of rates such that non-participating customer classes do not fund this component of the credit.

(*Id.* lines 22 to 31.) If the opt-in residential customers all respond to the PTR price signal by reducing their loads, there should not be any structural savings to estimate (or to put back into residential rates for recovery.) If it is still necessary to estimate structural savings, the burden would fall on the residential class alone. At this point, however, PTR has not been authorized for PG&E's residential customers.

VIII. CONCLUSION

Demand response programs rely on the willingness of customers to participate. Customers will only participate if they see a value proposition that is compatible with their ability and desire to reduce load. As such, PG&E and several other parties that represent the majority of the DR implementers (including the investor-owned utilities (IOUs), customers, and third-party DR providers (DRPs) are concerned that this preceding may focus on topics that will not do the most to expand cost-effective DR for customers. PG&E believes that this proceeding should have an additional focus on providing a wide range of opportunities for customers to participate in DR in order to attract the participation of as many customers as possible.

It is also critical that the Commission not act on assumptions that have not been verified and tested on an evidentiary record. Nor should the Commission ignore or overlook important factors that could be pivotal to a successful and robust outcome for the Rulemaking and the DR market(s) that may exist afterwards.

PG&E requests that the Commission carefully consider its comments, and act in accordance with the points made in this pleading, in order to position the DR market(s) to grow and prosper in the future.

Respectfully Submitted,

ANN KIM
SHIRLEY A. WOO
MARY A. GANDESBERY

By: */s/ Shirley A. Woo*
SHIRLEY A. WOO

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-2248
Facsimile: (415) 973-0516
E-Mail: SAW0@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 21, 2013

ATTACHMENT FOR
FOOTNOTE 1

ENERNOC

EnerNOC, Inc
275 Sacramento Street
Suite 300
San Francisco, CA 94111

Tel: 415 343 9500
www.enernoc.com
info@enernoc.com

September 17, 2013

Honorable Michael Peevey,
Honorable Mark Ferron,
Honorable Michel Florio,
Honorable Carla Peterman,
Honorable Catherine Sandoval,
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

SENT VIA ELECTRONIC MAIL

Dear President Peevey and Commissioners:

The Demand Response (DR) Collaborative is a group of utilities, DR aggregators, and end-use customers who came together 18 months ago to develop a roadmap for the further development of demand response (DR) in California and to identify roadblocks that need to be overcome. That roadmap has been shared with the Commission, the California ISO (CAISO), and the CEC in order to facilitate a strong and sustainable role for DR. Thus, it is with considerable interest that members of the DR Collaborative have read the Draft DR Rulemaking that is on the CPUC's Agenda for the September 19, 2013 open meeting. We would like to share some significant concerns we have with the Draft DR Rulemaking in advance of your consideration of this issue on Thursday. I am submitting these comments on behalf of the DR Collaborative in the spirit of providing constructive commentary in advance of the process.

The Draft DR Rulemaking demonstrates an overarching emphasis on DR that is bid into CAISO markets, and substantially de-emphasizes the value of DR as a demand-side resource, apart from pricing strategies and public alerts. This emphasis is not based on an analysis of the relative costs and benefits of wholesale market participation or the challenges of applying CAISO market requirements to DR. The DR Collaborative is concerned that the CAISO wholesale market will fail to provide the appropriate market signals to encourage DR resource development.

Further, it is important to recognize that DR resources rely upon the willing participation of customers. Customers are highly likely to decline to participate if they are forced into programs that fail to provide adequate financial incentives and if the program terms do not recognize the operational differences between DR and generation. The DR Collaborative is concerned that if all DR resources are required to participate under such conditions, the existing DR resource would collapse. Therefore, it is very important to maintain a focus on the role of the customers as DR resource providers to ensure that they remain engaged and motivated.

The members of the DR Collaborative, referenced in the concluding paragraph of this letter, encourage the Commission to consider a full spectrum of DR resource contributions in the DR Rulemaking, including DR for emergency and peak-shaving purposes. The Draft DR Rulemaking places a strong emphasis on the use of DR resources to integrate renewable resources. This represents a significant change in the current use of

DR resources. The Commission and the CAISO are engaged in defining the role of use-limited resources in providing flexibility and local reliability, but these processes are far from resolved.

The DR aggregators, the customers and the utilities have worked together for years to create the current programs. The emphasis in the Draft DR Rulemaking on supply-side resources may be at the expense of demand-side resources and could create great uncertainty for customers in existing DR programs. Customers have been providing DR, reliably, for many years and are troubled by the prospect of significant changes in program requirements that may result from this process. It is important for the Commission to minimize significant shifts in program structures and to provide as much advance notification as possible to customers, utilities and aggregators of program changes.

In summary, the DR Collaborative urges the Commission and other agencies to strongly consider the key elements of the DR Collaborative Roadmap (see attached presentation that was made to then CPUC Advisor Matthew Tisdale and presents the key elements) in shaping the future of DR, to be realistic about the role that DR can play in the CAISO wholesale market, to recognize its value as a demand-side resource, to recognize the operational differences between DR and generation, and to remember the customer-focused nature of DR.

The DR Collaborative looks forward to full participation in the DR Rulemaking and to providing constructive input. However, we hope the Commission will give due consideration to the concerns raised in this letter. The parties supporting the views expressed in this letter include EnerNOC, Inc., Comverge, Johnson Controls, Inc., North America Power Partners, APX, California Large Energy Consumers Association (CLECA), Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E).

Respectfully submitted on behalf of the DR Collaborative,

/s/ Mona Tierney-Lloyd,
Director, Regulatory Affairs

cc: Commissioner Andrew McAllister, California Energy Commission
Heather Sanders, California ISO
Edward Randolph, CPUC Energy Division
Simon Baker, CPUC Energy Division
Bruce Kaneshiro, CPUC Energy Division
Nicolas Chaset, Governor's Special Advisor on DG, CHP and Storage, CPUC
Joseph Como, Acting Director, Division of Ratepayer Advocates
Sudheer Gokhale, DRA
Members of the Demand Response Collaborative
Executive Staff, CPUC

Attachment

California Demand Response

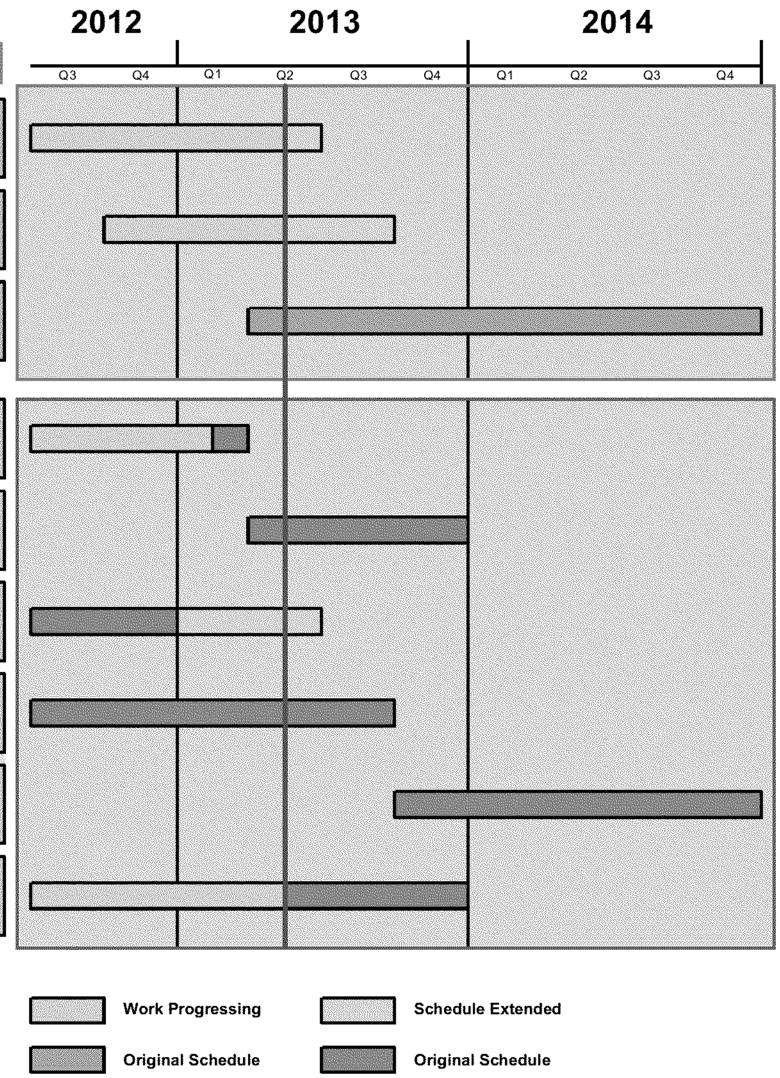
Near-Term Roadmap & Intermediate-Term Issues

Meeting with Matthew Tisdale

May 14, 2013

Roadmap to Achieve Near-Term Goals

		Activity	Initiative	Outcome
Participation	1	CAISO FERC 745 Resolution	CAISO New Initiative	Remove DLA
Participation	2	CPUC Direct Participation Ruling	CPUC DR Proceeding	Create Rule 24
Participation	3	IOU Rule 24 Implementation (and Application if Required)	IOU Implementation	Implement Systems Required to Allow Direct Participation by Customers
Capacity Payments	4	CPUC Cost Effectiveness Update: Portfolio and Dual Participation	CPUC DR Proceeding	Valuation Methodology that handles Dual Participation and Portfolio Approach
Capacity Payments	5	CPUC Cost Effectiveness Update	CPUC DR Proceeding	Valuation methodology for Different Types of Resources
Capacity Payments	6	CPUC RA Credit Mechanism	CPUC DR & RA Proceeding	Establish Accounting for DR NQC
Capacity Payments	7	CPUC Funding Stability	CPUC DR Proceeding	Explicit Guidelines on Length of Contracts for DR Resources and Price Certainty
Capacity Payments	8	RFP for New DR Resources	CPUC Procurement Review Group	New Fixed Length Contracts for DR
Capacity Payments	9	CAISO Need Determination	CAISO Flexible Capacity Initiative	Types and Requirements of Resources Needed



SB_GT&S_0146215

Roadmap Update (Next important short-term steps)

- The major Cost Effectiveness deficiencies must be fixed as quickly as possible. (Item 4)
  - Fixing the "A" factor, dual participation and budget allocations are essential items. Recent efforts from CPUC and E3 on "A" factor look promising.
  - We recommend that only essential items be the near-term focus and be completed in Q2 so they can be used for the 2015-17 DR applications. The other items may take much longer to resolve and should not be required for the 2015-17 application or new AMP RFOs in 2013.
- Flexible RA requirements for DR resources need to be established by Q3 for the IOUs to create DR programs in their 2015-2017 DR applications and AMP RFOs. This may not be feasible, but a delay in defining these requirements should not delay the 2015-17 DR application or new AMP RFOs. (Item 9)
- PG&E needs authorization to issue a new AMP RFO by late 2013. Waiting until after a decision on 2015-2017 DR applications risks allowing the current 2013-2014 contracts to lapse. (Items 7- 8)
- Parties are actively negotiating Rule 24 tariff language with good progress being made. The CPUC has postponed a May 3 workshop by 50 days. This should be a workable time frame. (Item 2)

Longer-Term DR Priorities

- The initial DR Roadmap was meant to address near-term issues.
- The DR Collaborative has been in place about a year and recently met to discuss longer-term priorities.
- Seven longer term items were identified.

Roadmap Update (Longer-term steps)

1. **Continue to follow the near-term DR Roadmap. Progress has been made so it is important to keep the momentum going.**
2. **Retail DR programs should continue to be supported, in addition to wholesale DR. Cost effective wholesale DR should be supported but mandating that all retail programs participate in the wholesale market would not be practical and would eliminate useful DR resources.**
3. **In order to provide a stable platform for DR resource growth, it is important to allow customers to gain experience with the wholesale market by starting with a simple product and then offering more "complex" options. This is how other markets have developed DR resources over time.**
4. Resolve implementation issues associated with DR participation in the wholesale market. Wholesale DR will not spontaneously appear until Rule 24; metering, telemetry and data requirements; and a capacity payment mechanism for DR are implemented.
5. Need State agency coordination to ensure that DR, EE,and the impact of dynamic rates are incorporated into the CAISO's load forecasts for planning & operational purposes
6. It is important to evaluate strategies for DR, EE, dynamic rates and DG to address the intermittent renewables problem. All of these resources can contribute to meeting or reducing flexible ramping requirements.
7. Wholesale DR requirements should be generally aligned with industry norms (i.e., other ISOs). Current CAISO DR requirements are generally more restrictive than other ISO/RTOs.

ATTACHMENT FOR FOOTNOTE 3

(Ken Abreu)

CPUC Demand Response Rulemaking (R.13-09-11)

Session 1: Bifurcation of Demand Response

Ken Abreu, PG&E
October 16, 2013

PG&E Confidential

Overview of Bifurcation

Demand Side DR	Supply Side DR
Characteristics:	
Primarily serves LSE, UDC and customer needs Dispatched by LSE or UDC CAISO informed of dispatch CAISO can dispatch for reliability Incorporated into LSE load bid/settlement	• Primarily serves CAISO needs • Provides mechanism for non-LSE's to bid into CAISO markets • Dispatched by CAISO • PDR, PL or RDRR
Strengths:	
Proven track record Long Experience Large Resource LSE can control costs, has the info UDC can manage distribution reliability and cost Customers tool to manage costs and other goals (enviro, etc.) Potential for innovation with new technology	• Directly serves CAISO operating needs: Ancillary services, imbalance energy, etc. • CAISO has direct control for reliability • Directly included in CAISO optimization • Allows non-LSE's to bid into CAISO markets
Challenges:	
Need to adjust to changing technology and industry Keep CAISO informed of load changes Assure CAISO can dispatch for reliability Assure CAISO factors into its operations and optimization to avoid double procurement	• New, with limited experience • Complex • Costly • CAISO does not have all the cost info • More regulatory control to FERC vs. CPUC

Overall Key Points

- The ultimate question should be – how can DR be used so it is most beneficial to customers (not IOUs, CAISO, aggregators or "markets")
- Maintain demand-side DR and incrementally grow supply–side DR where justified
- Regardless of which side DR sits, it should have the ability to offset system/local capacity needs
- Transitioning DR programs into supply-side resources must provide clear ratepayer benefits that justify the costs
- The definition of and need for "fast" and "flexible" DR to aid in renewable integration should be determined before a need is established to create large new DR programs
- IOUs and third parties have potential to provide both demand and supply-side DR
- All stakeholders (customers, IOUs, CAISO, aggregators, LSE's, regulators, etc.) will need to be open to changing past ways so that the full value of DR can be captured at least cost

ATTACHMENT FOR FOOTNOTE 4

(John Hernandez)

New Demand Response Rulemaking (R.13-09-011)

PG&E

Demand Response OIR – Session 4 IRM2

John Hernandez, PG&E
October 16, 2013

- PG&E has experience bidding and interacting in the CAISO market
  - 2009 -> Launched several DR pilots that demonstrated Ancillary Services
    - Participating Load Pilot (PLP):
      - Large Commercial and Industrial customers providing CAISO with Non-Spinning Reserves
      - First ever demonstration that used OpenADR (v1.0) to communicate between CAISO and participating customers
    - SmartAC Pilot:
      - Deployed 1600 residential customers to simulate Spinning/Non-Spinning Reserves
  - 2011 -> Launched pilot studying how DR can assist with Renewables Integration
    - Intermittent Renewable Management Pilot (IRM):
      - Leveraged PLP infrastructure to demonstrate DR customers providing regulation up/down (sub-4 second instructions)
      - Tested load reduction (Reg. Up) and load consumption (Reg. Down)
  - 2011 & 2012 -> Enabled a DR retail program (PeakChoice) that was bid-in as Proxy Demand Resource (PDR)

Present

- IRM2 has not started operations -> late Q4 2013 / early Q1 2014
- IRM2 is designed to provide third party DR providers (customers, aggregators, ESP, CCA) the ability to bid-in their retail DR resource into CAISO wholesale market in order to assist with renewables integration
- Goals and deliverables for 2014:
  - Third-party DR providers are able to gain market experience on how to interact with CAISO wholesale market
    - Scheduling, bidding, dispatching
  - Looking to obtain 10 MW
  - Demonstrate how DR resources can provide flexible services (from existing energy services) to assist with renewables integration
- IRM2 is looking at a diverse set of customer segments and end uses

IRM2 in 2015 should address the following:

- *Leverage the 2014 IRM2 experience*
  - *Customer, Third-Party, and CAISO experience*
    - *What works?*
    - *What needs improvement?*
    - *Any gaps to address?*
- *Validate suggested operating windows for when DR needs to show up*
  - *Opportunity assessment based on what customersmay be able to do*
- *Construct DR services like **load increasing** DR to assist with over-generation*

DR Participants by Bifurcation

Operators (Who dispatches DR resources)	Supply-Side Participants (Bid-into CAISO market) (PDR/RDRR/NGR) ❑ Direct Participation (Rule 24) ❑ Utility Pilot Program ❑ IRM2	Demand-Side Participants (Not bid-into CAISO market) ❑ Existing retail DR Programs*
• CAISO	• Participants: • IOU/LSE/CCA • Aggregators • Customers	*CAISO Operators are informed of any DR events*
• UDC • IOU/LSE	• N/A	• Participants: • IOU/LSE/CCA • Aggregators • Customers

*Base Interruptible, Capacity Bidding, Demand Bidding, Peak Day Pricing, SmartAC, SmartRate and Aggregator contracts