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Witness(es): Kenneth E. Abreu
Steven R. Haertle
Nicholas K. Ho
Stephen J. Kung
Luke A. Tougas

PACIFIC GAS AND ELECTRIC COMPANY

2013 DEMAND RESPONSE RULEMAKING 13-09-011

PHASES 2 AND 3

OPENING TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
2013 DEMAND RESPONSE RULEMAKING 13-09-011
PHASES 2 AND 3
OPENING TESTIMONY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
DEMAND RESPONSE PROGRAM GOALS

A. Summary

- Pacific Gas and Electric Company (PG&E) supports an aspirational goal for Demand Response (DR), as long as it does not discriminate between Load Modifying Resource and Supply Resource DR, and as long as it does not serve as an absolute procurement requirement but rather as a starting point for discussion around what more should be done to encourage cost-effective DR in California.
- PG&E recommends that the California Public Utilities Commission (CPUC or Commission) avoid quantitative megawatt (MW) goals for DR and instead focus on implementing an action plan that enables the maximum amount of cost-effective DR to be deployed in California. The effectiveness of this action plan can be tracked though the amount of DR the investor-owned utilities (IOU) have in operation and under contract each year.
- Maximizing the amount of cost-effective DR deployed in California can be achieved by unlocking the full range of potential benefits associated with DR, minimizing the costs of delivering DR, and reducing the risks for participants in the DR market.
- The Commission and the California Independent System Operator (CAISO) can take various actions that will remove or minimize obstacles that prevent IOUs and third parties from capturing the maximum amount of cost-effective DR in California, including:
  - Address the major cost-effectiveness methodology issues identified by the parties in previous workshops.
  - Address challenges associated with DR participation in CAISO markets, including the cost and complexity of implementing Proxy Demand Resources (PDR) and Reliability Demand Response Resources (RDRR), before requiring DR to participate on a large scale.
  - Allow IOUs to procure DR through multiple avenues, including long-term Requests for Proposals (RFP), to promote a variety of DR products and customers.

– Initiate a process to ensure resolution of key obstacles to customer and third-party participation in the California DR market.

- The Commission should ensure the "equality" of Load Modifying Resource DR and Supply Resource DR though non-discriminatory treatment of the costs and benefits of both forms of DR. This includes the use of a consistent valuation framework (e.g., the Commission's cost-effectiveness protocols) to evaluate all DR programs and contracts, regardless of whether they function as a Supply Resource DR or a Load Modifying Resource DR.

B. Introduction

Q 1 Please state your name and the purpose of your testimony.

A 1 My name is Nicholas K. Ho and the purpose of my testimony is to respond to questions related to DR program goals included in Attachment A to the April 2, 2014 Joint Assigned Commissioner Ruling (ACR) Revising Scope and Schedule for the 2013 DR Rulemaking Phases 2 and 3.[1] My qualifications are included in Exhibit (PG&E-1).

C. Responses to ACR DR Program Goal Questions

Q 2 Please provide past and current goals for demand response so that this proceeding has a complete and accurate history of the goals.

A 2 In Decision 03-06-032, *Interim Decision in Phase 1 Addressing Demand Response Goals and Adopting Tariffs and Programs for Large Customers*, the Commission addressed MW goals for price-responsive DR, and the Commission's broader 2002-2007 Vision for the Future.[2] The MW DR goals were to be phased in to culminate in 5 percent of annual system peak load for each IOU over a 5-year period ending in 2007. Following that, the Commission proposed a set of qualitative goals in its October 1, 2007 *Assigned Commissioner's and Administrative Law Judge's Ruling Revising Phase 2 Activities and Schedule* in Rulemaking 07-01-041 (October 1, 2007 Ruling).[3] In addition, the October 1, 2007 Ruling examined the reasons why

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1 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings.

2 http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/26965.PDF.

3 http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=7785.

the 5 percent goal established in Decision 03-06-032 had not yet been met. Parties provided comments on November 26, 2007 and reply comments on December 7, 2007. However, no subsequent Commission decision was issued on DR goals in that proceeding so the proposed goals were never adopted.

In Decision 09-08-027 approving the IOUs' 2009-2011 DR program applications, the Commission ordered the IOUs to propose modifications to one or more of their DR programs to achieve 10 percent of DR enrollment in PDR.[4] In response, PG&E performed work discussed by PG&E witness Stephen Kung in Chapter 3 to enable its PeakChoice™ DR program to bid DR from its participating non-residential customers into the CAISO's Integrated Forward Market (IFM) (i.e., day-ahead energy market) as PDR. PG&E bid its PeakChoice into the CAISO's IFM beginning on July 12, 2011 through 2012. As I discuss below, the Commission later eliminated funding for the program after 2012. Table 1-1 provides a summary of the deployment of PeakChoice as a PDR in 2011 and 2012.

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF PEAKCHOICE AS A PDR

Line No.	Program Year	PDR Resources	No. of Registered Participants	No. of Bids Submitted to the CAISO	No. of Bids Accepted by the CAISO
1	2011	2	35	75	1
2	2012	6	35	366	11

PG&E proposed to continue to use its PeakChoice program to bid DR into the CAISO market in its DR application for 2012-2014, and also issue a RFP for DR that could be bid as PDR in the CAISO market. However, in Decision 12-04-045, the Commission declined to renew funding for the PeakChoice program beyond 2012, thus eliminating the one program that at the time PG&E could successfully bid into the CAISO market. In addition, because Decision 12-04-045 was approved in April 2012, there was an insufficient amount of time for PG&E to issue a RFP for what is now defined

4 Decision 09-08-027, Ordering Paragraph (OP) 25.

as Supply Resource DR so PG&E only issued an RFP for what is now defined as Load Modifying Resource DR. In eliminating PeakChoice, the Commission ordered PG&E to submit an advice letter describing how it would meet the 10 percent PDR requirement.[5] On July 30, 2012, PG&E submitted Advice Letter 4093-E proposing to use the Demand Bidding Program (DBP) customers that are dual participating in the Base Interruptible Program (BIP) to bid in the CAISO's IFM as a RDRR. The Commission has not yet ruled on this advice letter. PG&E is unaware of any other DR-related goals that have been established by the Commission.

Q 3 Please provide recommendations for increasing individual DR program load impacts and overall participation in DR programs. If current DR participation levels are appropriate, please explain why.

A 3 Capturing the full potential of the DR market is simply a matter of increasing the benefits associated with DR resources, and reducing the costs and risks of providing such resources so that maximum value can be shared between providers of DR programs and participating customers. Therefore, in order to maximize the amount of cost-effective DR in California, the Commission should pursue an action plan to increase the benefits and reduce the costs and risks to participating customers and providers of DR programs. The benefits of DR can be grown by identifying and unlocking new valuable applications of DR (e.g., Transmission and Distribution investment deferral, renewables integration). Costs and risks of securing DR can be reduced by rationalizing the operational requirements for providers of DR, creating financial certainty for market players, and providing the market the freedom to choose how it wants to participate. Below, I explain in greater detail steps that the Commission and CAISO can take to drive additional benefits and reduce costs/risks for market participants. In addition, these quantitative and qualitative benefits and costs of DR must be accurately reflected in the cost effectiveness calculations used to achieve Commission approval. I discuss specific recommended changes to the DR cost effectiveness protocols below.

5 Decision, OP 40.

The Commission and CAISO can take several actions that will promote greater supply of DR in California. The Commission should focus its efforts on a few key levers to maximize the quantitative and qualitative benefits associated with DR resources, as well as minimize the costs and risks associated with providing DR. The Commission should also note that the nature of these levers is likely to evolve over time as market participants gain experience and new enabling technologies enter the market. Below I describe some of the more immediate opportunities to grow the DR market in California.

- **Revise the DR cost-effectiveness methodology:** Decision 10-12-024 established the DR cost effectiveness protocols and stated that all IOU DR programs must be cost effective under the protocols until told otherwise by the Commission.[6] Specifically, the DR cost-effectiveness methodology dictates which DR resources (programs) provide benefits that outweigh their costs; the results of this calculation are used to identify which DR resources are ultimately pursued. Insofar as the DR cost effectiveness protocols undervalues or disregards certain benefits, or artificially inflates the cost of such resources, it will limit the range of opportunities available for customers and DR providers to supply cost-effective DR. It is important to note that DR comes in many shapes and sizes to address different needs on the grid, and the cost effectiveness protocols need to acknowledge and appropriately value all forms of DR to ensure that the full potential of the DR market is captured.

There are a number of critical weaknesses in the current methodology that should be addressed. Pursuant to Decision 12-04-045, the Energy Division conducted a workshop on October 19, 2012 where parties provided input on potential improvements to the DR cost effectiveness protocols.[7] At that workshop there was general consensus on how to fix some of the major deficiencies which were: (1) modifying the "A" factor; (2) treatment of dual participation; and (3) allocation of overhead costs. After the workshop, the Energy Division issued 44 follow-up questions for parties to respond to.

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6 Decision, OP 2. The Commission exempted dynamic rates and DR pilot programs from the cost effectiveness requirement.

7 Decision, OP 7.

PG&E has attached its response to the 44 questions, which include specific recommended changes to the cost effectiveness protocols, as Appendix D.

The April 2, 2014 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase 2, and Providing Guidance for Testimony and Hearings indicates there is an insufficient record for revising the DR cost effectiveness protocols but it asks no questions on this issue. It is very important to revise the protocols because, to a great extent, they dictate what DR programs the IOUs can offer customers. PG&E recommends that the protocols be revised to recognize the quantitative and qualitative benefits associated with DR that can provide fast response, localized dispatch (e.g., at the substation level), upward or downward ramping, or be bid and dispatched in the CAISO market.

The importance of revising the DR cost effectiveness protocols is illustrated by the elimination of PG&E's PeakChoice program. As mentioned above, this program was the vehicle for PG&E to meet the Commission's goal that 10 percent of IOUs' DR must participate in the CAISO market as PDR. However, PeakChoice was eliminated in the Commission's 2012-2014 DR portfolio decision, despite the Commission's goal of having IOU DR bid into the CAISO market, because it was found to be not cost effective. Bidding DR into the CAISO market introduces incremental costs and risks to IOUs and customers compared to DR that is not bid into the CAISO market.[8] Until the cost effectiveness protocols are revised to correct the problems with the A factor, dual participation, allocation of overhead costs, and to recognize the quantitative and qualitative benefits of DR programs that provide greater functionality such as CAISO market integration, fast ramping, distribution-level dispatch, ramping, etc., and ensure that DR programs offering these types of benefits are not disadvantaged in any way in the valuation process, it will be difficult for the IOUs to get Commission approval of new Load Modifier Resource DR and Supply Resource DR programs.

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8 These costs are explained in detail in PG&E's response to Commission questions on CAISO Market Integration Costs.

- **Address challenges associated with DR participation in CAISO markets before requiring DR to participate on a large scale:** In Table 2 of Decision 14-03-026, the Commission proposes to categorize the Aggregator Managed Portfolio (AMP), DBP, Capacity Bidding Program, Air Conditioner Cycling, Agricultural Pumping Interruptible and BIP as Supply Resource DR programs.[9] According to the definition of Supply Resource DR in OP 2 of this decision, these programs would all be required to be bid into the CAISO market.

  As we address in the following chapters and appendices, there are still a number of very significant obstacles that stand in the way of integrating DR with the CAISO markets on a large scale.[10] As PG&E witness Ken Abreu discusses in Chapter 4 of PG&E's testimony, using manual procedures, PG&E plans to bid 10-20 MW in 2014 based on existing CAISO processes and procedures. However, integrating more of PG&E's DR programs into the CAISO market will likely be very costly without significant changes, many of which are discussed in the testimony of PG&E witness Spence Gerber in Appendix B and Dr. Papalexopoulos in Appendix A. The fragmentation of resources necessitated by current CAISO market rules, for example, introduces substantial administrative costs for market participants. The IOUs face the challenge of obtaining permission from third-party energy service providers to bid Direct Access customers on their DR programs into the CAISO markets.[11] Putting aside situations in which it is currently infeasible to integrate certain DR customers or resources into the CAISO markets, mandating the integration of IOU DR programs without first ensuring the resolution of fundamental challenges in the CAISO markets will burden providers of DR resources with substantial additional costs, which, in turn, will negatively impact cost effectiveness and limit opportunities for customers to engage in DR.[12] Instead, the Commission should condition the requirement to integrate DR resources into the CAISO markets on the

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9 Decision, p. 21.

10 See Exhibit (PG&E-1), Appendices A, B and C for a full discussion these issues.

11 See Exhibit (PG&E-1), Appendix B.

12 See Exhibit (PG&E-1), Appendix C.

satisfactory resolution of key obstacles identified in this proceeding, as opposed to an arbitrary date in the future.[13]

Furthermore, requiring all existing IOU DR programs to participate in the CAISO markets could expose DR providers to additional financial risks. These risks could, in turn, be passed on to customers in the form of higher penalties, lower incentive payments, or even more frequent dispatches and have a negative impact on the amount of DR that is supplied in California. For example, the disaggregation of resources required by the CAISO markets (e.g., by Load Serving Entity, by Sub Load Aggregation Points) will introduce additional performance risk on the part of DR providers, as they lose opportunities to pool risk across their customer portfolios. This may drive DR providers to be more conservative in their market (or contractual) commitments, which reduces the value of the resources and, therefore, the amount that can be paid to customers. One way to mitigate this negative outcome is to preserve programs that are not required to integrate with the CAISO markets. This way, DR providers have the freedom to choose whether the additional risk they incur in the CAISO markets is worth the additional value assigned to those programs.

- **Authorize IOUs to issue more RFPs, with sufficient lead time, for Load Modifying Resource and Supply Resource DR:** The Commission should provide the IOUs greater flexibility to issue RFPs for Load Modifying Resource DR and Supply Resource DR. PG&E has been successful in its limited use of RFPs to solicit DR for the AMP program. Expanding their use will enable the IOUs to procure more MW of DR, and more types of DR, including Supply Resource DR. Utilizing more RFPs will promote a robust third-party market by providing an opportunity for them to offer specialized products such as PDR, ancillary services, and flexible capacity. Longer contract durations will provide third-party DR providers with the economic certainty needed to make long-term investments in customer acquisition, technology deployment, and program development, all of which are required to expand the DR market in California. It should be noted that for new

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13 See Exhibit (PG&E-1), Appendices A and B, for discussion of obstacles as well as possible ways to reduce the cost and complexity of Supply Resource DR.

generation-side resources, long-term contracts (generally longer than 10 years) are used and so it is reasonable to expect that a somewhat similar need exists for DR resources to provide the certainty needed for them to fully invest in a market.

Furthermore, RFPs can unlock additional valuable DR resources that may not show up under the Commission's Demand Response Auction Mechanism (DRAM) proposal. Putting aside the issue that the Commission's DRAM proposal will exclude third-parties who are simply not interested in or capable of providing Supply Resource DR, the RFP approach provides much more flexibility for the IOUs to work with DR providers on agreements that bring the maximum amount of DR to the state. While standard product definitions and contract terms could help make DRAM an efficient vehicle for procuring some types of DR, PG&E's experience with DR RFPs has shown that some flexibility in these areas (e.g., settlement structure) is needed to fully leverage third parties' ability to bring valuable DR resources to market.

Finally, PG&E recommends that the Commission, when authorizing the IOUs to issue RFPs for third-party DR, build in at least one year of lead time from contract approval to the beginning of the delivery period. In PG&E's 2012-2014 DR program application, PG&E proposed to issue a new RFP for third-party PDR DR that would have replaced the then-existing contracts due to expire at the end of 2011. PG&E had planned to issue its RFP in early 2012, with approximately one year for bidders to respond to the RFP, enroll customers, and make any necessary investments in time to deliver beginning in the summer of 2013. However, Decision 12-04-045 was approved in April 2012 and although it allowed the IOUs to extend their AMP contracts through 2012,[14] it directed the IOUs to either renegotiate the existing contracts for 2013-2014 or issue a new RFP for these two years.[15] The deadline for renegotiation of existing contracts was 90 days. For new contracts, the IOUs only had four months before the filing deadline for the application to obtain contract approval. Four months was an insufficient

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14 D.12-04-045, OP 14.

15 D.12-04-045, OP 15.

amount of time for PG&E to conduct a RFP for PDR DR, aggregators to make a serious assessment of how much DR they could provide to be bid as PDR, and develop an application for Commission approval of the contracts. So, PG&E issued a RFP for retail DR rather than the wholesale DR it had originally planned to obtain.

- Focus on how to grow DR while addressing the needs of customers, as well as the future needs of the grid, rather than focusing solely on bidding DR as a Supply Resource: Over the past several years, significant regulatory effort has been spent on policy issues and programmatic approvals that have not fundamentally impacted the DR landscape in California. While we certainly believe there is value in addressing the topics in scope for this current proceeding, we urge the Commission to avoid dwelling solely on the issues of CAISO market integration and DR procurement to the detriment of DR overall. Instead, the Commission should also consider other issues that could enable DR to play a significantly larger and more valuable role.

At the most basic level, if the Commission's goal is to obtain more DR, we should explore how to get existing DR customers to provide more DR, as well as how to get new customers into DR programs. A discussion of current obstacles to customer participation should yield insight into what program changes and new programs could be useful in increasing customer participation. These insights could form the basis for the IOUs' next round of program applications.

The Commission should also pursue a separate (but related) discussion on how DR will need to evolve and expand to continue to serve the needs of the grid. Under what conditions do we want DR to be called? How will DR need to respond? If the Commission finds that multiple forms of DR will continue to be relevant in the future, is there a specific amount that is needed of each? Again, having answers to these and other related questions will help all providers of DR to start building the capabilities and resources needed to serve the grid in the future.

- **Authorize the IOUs to conduct more marketing of their DR programs, especially the BIP:** PG&E believes that its existing BIP could provide significant additional valuable DR capacity if it had the opportunity to market it to its customers. The BIP currently has a loyal customer base owing to its strong customer value proposition, which includes robust and predictable incentive payments without excessive disruption to customer operations. In exchange, BIP customers provide one of the most responsive and reliable DR resources in the DR portfolio, available to meet both transmission- and distribution-level reliability needs every day of the year.

The BIP's value to the electrical grid was recently demonstrated when it was successfully dispatched in response to stressed conditions on the CAISO system on February 6, 2014. The CAISO requested PG&E to dispatch the BIP because natural gas shortages in southern California precluded some generators from operating. Despite being dispatched in the middle of the winter when cooling loads are lowest, BIP participants delivered, as forecasted, 180 MW of valuable load reduction.

In Decision 12-04-045, no local marketing dollars were approved for the BIP, effectively precluding marketing for BIP even though the current size of PG&E's program is well below the Commission-imposed cap on reliability-based DR that was approved in Decision 10-06-034. Given the opportunity to attract additional customers to the BIP, the versatility and proven effectiveness of the program, and the fact that PG&E is still well below the Commission-approved cap on reliability-based DR, we recommend that the Commission authorize the use of existing funding to enable PG&E to resume marketing-related activities for the BIP.

- **Explore best practices from other states and markets:** Though California has been deploying DR in various forms since the 1980s, other states and Independent System Operators/Regional Transmission Organizations have more experience in some aspects of DR. For example, PJM, NYISO, ERCOT and ISO-NE have extensive experience in integrating DR into their wholesale markets. The Commission, with the participation of parties, should seek to identify these best practices, as appropriate for the California market, and use them to help inform the evolution of DR in California.

Q 4 Please provide recommendations for developing the goals of demand response load (MW) and demand response participation, how those goals should be measured (load impact protocol based on *ex post* or *ex ante*, or others), and how often they should be measured to ensure goal achievement (monthly, seasonally, or annually).

A 4 PG&E supports the establishment of aspirational goals for DR capacity (MW) and participation, as long as they: (1) do not discriminate between Load Modifying Resource DR and Supply Resource DR; and (2) are used solely for the purpose of driving conversation around what further actions, if any, are required to promote more DR in our state. These aspirational goals, however, should not be used to set hard procurement targets, especially without serious consideration for resource need (in the context of the Commission's Resource Adequacy and Long-Term Procurement proceedings), overall DR potential and/or cost effectiveness (as defined in the Commission's cost-effectiveness methodology).

An aspirational goal for total DR capacity (MW) operated and/or procured by the IOUs could be used to provide guidance for future IOU DR applications. The Commission should commission a regularly-conducted DR potential study to determine the available amount of technical and economic DR potential in each IOU service area by customer class and inform the aspirational goals. On the basis of this forecasted potential, IOUs could be required in their applications to propose cost-effective programs and procurement activities that most closely satisfy their respective aspirational goal.

Following approval of the IOUs' applications, the IOUs would be responsible for reporting—on an annual basis via their annual DR Load Impact filing—how much DR capacity they expect to have available in the future on an *ex ante* basis. Where the annual DR Load Impact forecasts deviate significantly from the plans described in the IOUs' DR applications, the IOUs should be prepared to explain the reasons behind the variances.

A procurement target for any type of demand response is not necessary at this time. With an aspirational goal for DR procurement and enrollment, our real objective should continue to be the maximization of cost-effective DR. This approach recognizes that, regardless of what steps are taken by the IOUs and third-party DR providers, customers interested in participating in a DR program will only participate if it is easy to do so, it is economically worth their while, and if they are not overly inconvenienced in the process. If the Commission implements "hard" DR goals without the proper analysis of potential and a plan to meet that potential, the Commission would be dismissing the reality of customer choice and/or presupposing the willingness of customers to participate in DR programs. It is now and should continue to be the customer's choice to participate in a DR program.

Establishing a "hard" DR goal could drive higher prices for DR resources, especially in a supply-constrained environment. In PG&E's last DR RFP, all cost-effective bids were accepted, reflecting the relative scarcity of DR resources in the market. However, if a hard DR MW goal was established without consideration of cost, the price of DR could be driven much higher than what would be consider cost effective under the DR cost effectiveness protocols.

The Commission should establish qualitative goals that are supported by an implementation plan that meets forecasted needs. When deciding what DR to promote, the Commission should be sure that it reflects current and future system needs as determined in the Commission and CAISO planning processes. Making these changes will likely require coordination among a variety of proceedings and stakeholder initiatives at the Commission, CAISO and the California Energy Commission, and are dependent on developments before each of these organizations. The interrelationships of the various proceedings and stakeholder initiatives need to be clearly understood, as well as coordinating which issues will be decided in each proceeding and in what sequence. Setting a plan and schedule for accomplishing those changes will be a significant, constructive step towards creating additional cost effective DR (as compared to simply setting an annual numerical MW DR goal). Furthermore, the implementation plan should reflect a phased approach to DR directly participating in the CAISO markets. A phased approach will allow time for problems to be identified and solved before moving forward with full-scale infrastructure deployment. As Mr. Spence Gerber, PG&E's witness from Olivine, explains in his testimony, the implementation of the IRM 2 pilot has exposed weaknesses in the process of bidding DR as PDR into the CAISO market.[16] It is better to address these issues in the context of a pilot program rather than in the context of large scale deployment of new types of DR which could negatively impact participation. Another benefit of an implementation plan is that it will provide more regulatory certainty for all entities involved.

Q 5 Please provide recommendations for programs or activities to ensure equality for load modifying resources and supply resources. Parties should suggest a definition for equality.

A 5 In comparing Load Modifying Resource DR and Supply Resource DR, PG&E would define "equality" as the non-discriminatory treatment of the costs and benefits of both Load Modifying Resource DR and Supply Resource DR. This definition of "equality" is especially important in the valuation of DR resources for procurement purposes, as well as their integration into resource planning exercises.

The decision to pursue (procure) any DR resource, regardless of its classification as Load Modifying Resource DR or Supply Resource DR, should be based on a common valuation methodology, which could include the Commission's DR cost-effectiveness protocols once the major deficiencies are fixed and they are amended to accurately reflect the different capabilities of DR resources. PG&E does not believe that the cost-effectiveness evaluation described in the current DRAM proposal ensures equality between Load Modifying Resource DR and Supply Resource DR, as it potentially allows Supply Resource DR to be procured at a price in excess of what would be permitted by the Commission's own DR cost-effectiveness protocols. Instead, PG&E recommends that the Commission use the same cost-effectiveness protocols in the DRAM as it does in evaluating the IOU's existing DR programs.

D. Conclusion

Q 6 Does this conclude your testimony?

A 6 Yes, it does.

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16 See Exhibit (PG&E-1), Appendix B.

PACIFIC GAS AND ELEC TRIC COMPANY

CHAPTER 2

RESOURCE ADEQUACY CO NSIDERATIONS

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RESOURCE ADEQUACY CONSIDERATIONS

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RESOURCE ADEQUACY CONSIDERATIONS

A. Introduction

Q 1 Please state your name and the purpose of your testimony.

A 1 My name is Luke A. Tougas and the purpose of my testimony is to respond to questions related to Demand Response (DR) program Resource Adequacy (RA) considerations included in Attachment A to the April 2, 2014 Joint Assigned Commissioner Ruling (ACR) revising scope and schedule for the 2013 Demand Response (DR) Rulemaking Phases 2 and 3, in Rulemaking 13-09-011.[1] My qualifications are included in Exhibit (PG&E-1).

B. Responses to ACR RA Consideration Questions

Q 2 Please provide a detailed explanation of their resource adequacy concerns, specific to the bifurcation framework adopted in Decision 14-03-026.

A 2 It is essential that, all things being equal, both Load Modifying Resource DR and Supply Resource DR receive comparable RA value that reflects the generation capacity they are avoiding. This will assure that we are not disadvantaging one over the other or diminishing the value of one relative to the other. However, due to the nature of the definitions of these two types of DR, their RA value should be realized in different ways. According to Ordering Paragraph (OP) 2 in Decision 14-03-026, Load Modifying Resources are defined as “resources that reshape or reduce the net load curve.” Conversely, OP 3 defines Supply Resource DR as “resources that are integrated into the California Independent System Operators energy markets.” Given these definitions and how each type of DR impacts the net load curve, it would be logical for Load Modifying Resource DR to reduce the RA requirement, and Supply Resource DR should meet the RA requirement. This position is supported by Pacific Gas and Electric Company witness Dr. Alex Papalexopoulos on pages 7-8 of his testimony in

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1 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings.

Appendix A and by Dr. Jay Zarnikau on pages 8-9 of his testimony in Appendix C.

C. Conclusion

Q 3 Does this conclude your testimony?

A 3 Yes, it does.

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CHAPTER 3

CAISO INTEGRATION CO STS

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CAISO INTEGRATION COSTS

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CHAPTER 3
CAISO INTEGRATION COSTS

A. Summary

- The costs of bidding Supply Resource Demand Response (DR) into the California Independent System Operator Corporation (CAISO) market are significant.
  - Pacific Gas and Electric Company (PG&E) is the only entity that has bid or facilitated a bid through a pilot and has received a dispatch for a DR program as a Proxy Demand Resource (PDR) in the CAISO market.
  - PG&E can rely on the increased understanding gained from its experience with PDRs to forecast costs to inform its estimates for integrating Supply Resource DR into the CAISO market.
  - Shown below is a summary of the estimated technology costs as discussed in this chapter. Please note that many of these costs rely on the prior project being completed and cannot be abstracted as a stand-alone cost. Table 3-1 also excludes Electric Rule 24 implementation costs, which are still under development and are planned for filing on June 2, 2014.

TABLE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF ESTIMATED TECHNOLOGY COSTS

Line No.	Phase	Name/Short Description	Actual or Estimated Costs	Implemented or Future Scope
1	PDR Phase 1	PeakChoice™ as PDR Day Ahead Energy	$16.1M	Implemented
2	RDRR	Convert BIP for RDRR Real Time Energy	~$4M - $5M	Future Scope
3	PDR Phase 2	Convert CBP for PDR Day Ahead Energy	~$3M - $5M	Future Scope
4	PDR Phase 2	Convert SmartAC™ for PDR Day Ahead Energy	~$7M - $8M	Future Scope
5	PDR Phase 2	Convert AMP for PDR Day Ahead Energy	~$1M - $2M	Future Scope
6	PDR Phase 2	Expand PDR platform to enable Real Time Energy	~$1M - $4M	Future Scope
7	PDR Phase 2	Convert SmartAC for PDR Real Time Energy	~$1M - $2M	Future Scope
8	PDR Phase 2	Expand PDR platform to enable ancillary services (excludes telemetry)	~ $2M - $4M	Future Scope

- The California Public Utilities Commission (CPUC or Commission) should allow for a transition period to allow parties (including the CAISO) to gain experience and reduce costs as more Supply Resource DR enters the market.
  – Experience gained by bidding Supply Resource DR into the CAISO market will likely identify opportunities for all parties to simplify processes and potentially lower costs.
  – There are opportunities to reduce the costs and complexity of integrating as Supply Resource DR, primarily by modifying the CAISO's processes.
- This chapter covers only a portion of PG&E's technology costs to address some cases to implement DR as Supply Resource DR. There are additional costs for other cases that are not included in the PG&E technology cost estimates here. Also, the CAISO and other market participants will incur additional costs that will ultimately impact ratepayers.

B. Introduction

Q 1 Please state your name and the purpose of your testimony.

A 1 My name is Stephen J. Kung and the purpose of my testimony is to respond to questions related to the cost of integrating PG&E's DR programs into CAISO wholesale electricity markets. These questions were included in

Attachment A to the April 2, 2014 Joint Assigned Commissioner Ruling (ACR) revising scope and schedule for the 2013 DR rulemaking Phases 2 and 3.[1] My qualifications are included in Exhibit (PG&E-1).

C. Responses to ACR CAISO Integration Cost Questions

Q 2 Please provide your understanding of the costs (in dollars) of the CAISO market participation either through their own direct participation or through the participation of other entities in other markets.

A 2 PG&E can only speak to its own costs, not the costs of the CAISO and other market participants. From PG&E's perspective, the costs associated with building and operating the infrastructure to enable its DR programs to be bid into the CAISO market are significant relative to the costs of the programs themselves. As PG&E witness Mr. Kenneth E. Abreu discusses in Chapter 4 of PG&E's testimony, these costs are significant relative to the incremental benefits associated with bidding DR in the CAISO market versus operating them outside of the CAISO market.

In this chapter, I discuss estimated high level technology costs necessary to support information technology system changes, given the complexity of CAISO market processes and the numerous cases with different roles that PG&E is required to fulfill to enable CAISO market integration. I will also describe how PG&E has investigated over 18 different cases in which PG&E or others may fulfill roles for the Load Serving Entity (LSE), Meter Data Management Agent (MDMA), and/or Demand Response Provider (DRP). Each case is further addressed for each of the five different PG&E DR programs described, the two different CAISO markets of Day Ahead (Integrated Forward Market) and Real Time (Real-Time Market), and the CAISO products of Energy, and Ancillary Services (AS). Each combination of roles, products, markets, and DR programs creates added complexity, effort and costs. This chapter covers only the technology asset costs needed to support the functions for market integration based on each of the roles to be filled as described as certain cases. A matrix of the

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[1] Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings, April 2, 2014, in Rulemaking 13-09-011.

different cases is shown in Figure 3-1. Only a limited number of the possible cases have been estimated. And the costs for some of the cases not estimated may be significant.[2]

As these are the costs for the information technology asset, there are other associated costs that have not been estimated or presented in this chapter. These include: (1) operations and maintenance, (2) training, (3) telemetry changes, (4) business process redesign\development, and (5) business-related costs associated with the fulfillment of each of the roles. This also does not include CAISO and customer implementation costs,

To date, PG&E has only implemented one subset of one case of PDR indicated as PDR Phase 1 (PDR1) for Day Ahead Energy shown in Figure 3-1 under Case 1a. Additional cases are addressed in future scope to be defined in PDR Phase 2 (PDR2), Reliability Demand Response Resources (RDRR), and Electric Rule 24 (Rule 24). Figure 3-1 represents the cases that PG&E has investigated and discusses in this chapter (i.e., the scope of PDR1, PDR2, RDRR, and Rule 24). For the case combinations of role, program, market or product denoted, those with an "x" are subsets of cases that were not investigated. Reasons for their exclusion include incompatibility of the current DR program design with the CAISO market\product integration requirements, or process and interface limitations that would not have a clear development path based on current implementations. However, in the future, these issues may be resolved and these additional cases estimated and considered for potential implementation.

2 PG&E has not studied all possible cases.

FIGURE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
MATRIX OF DIFFERENT PDR, RDRR, AND ELECTRIC RULE 24 CASES

						Day Ahead Market			Real Time Market	
Case	Customer	LSE	MDMA	DRP	Program	Energy	RUC	AS	Energy	AS
1a	Bundled	PG&E	PG&E	PG&E	Peak Choice	PDR1	x	x	x	x
1b	Bundled	PG&E	PG&E	PG&E	CBP	PDR2	x	x	x	x
1c	Bundled	PG&E	PG&E	PG&E	AMP	PDR2	x	x	x	x
1d	Bundled	PG&E	PG&E	PG&E	Smart AC	PDR2	x	x	PDR2	x
1e	Bundled	PG&E	PG&E	PG&E	BIP	x	x	x	RDRR	x
2	Bundled	PG&E	PG&E	3rd party	N/A	Rule 24	Rule 24	Rule 24	Rule 24	Rule 24
3a	CCA	3rd party	PG&E	PG&E	CBP	PDR2	x	x	x	x
3b	CCA	3rd party	PG&E	PG&E	AMP	PDR2	x	x	x	x
3c	CCA	3rd party	PG&E	PG&E	BIP	x	x	x	RDRR	x
4a	DA	3rd party	PG&E	PG&E	CBP	PDR2	x	x	x	x
4b	DA	3rd party	PG&E	PG&E	AMP	PDR2	x	x	x	x
4c	DA	3rd party	PG&E	PG&E	BIP	x	x	x	RDRR	x
5	CCA	3rd party	PG&E	3rd party	N/A	Rule 24	Rule 24	Rule 24	Rule 24	Rule 24
6	DA	3rd party	PG&E	3rd party	N/A	Rule 24	Rule 24	Rule 24	Rule 24	Rule 24
7a	DA	3rd party	3rd party	PG&E	CBP	PDR2	x	x	x	x
7b	DA	3rd party	3rd party	PG&E	AMP	PDR2	x	x	x	x
7c	DA	3rd party	3rd party	PG&E	BIP	x	x	x	RDRR	x
8	DA	3rd party	3rd party	3rd party	N/A	Rule 24	Rule 24	Rule 24	Rule 24	Rule 24

Note: "x" denotes a product market program combination that has not been scoped for this discussion.

To my knowledge, PG&E is the only entity that has bid or facilitated a bid through a pilot and has received a dispatch for a DR program as a PDR in the CAISO market. Our experience in building the infrastructure to enable the bidding and dispatch of these programs into the CAISO market is useful, but the systems required to address additional cases of roles, DR programs, CAISO markets, and CAISO products, will need to do more and will require significant costs. However, our experience has provided several insights into how to implement the large-scale deployment of DR into the CAISO market.

Below, I provide the estimated and, when applicable, actual costs of developing the key infrastructure necessary to enable PG&E DR programs to bid and be dispatched in the CAISO market. I discuss the market integration projects in four parts:

1. **Proxy Demand Resource Implementation:** The actual costs of modifying PG&E's systems and processes to create a platform for integrating PG&E's DR programs, as appropriate, into the CAISO's

Integrated Forward Market (IFM) (i.e., day-ahead) market as PDRs.[3] This implementation operationalized foundational elements needed to support CAISO PDR for the PG&E PeakChoice[4] program and potentially reusable functionality that could be leveraged for other DR programs, and is referred to as PDR1 throughout this testimony. This implementation offered PeakChoice PDR as day-ahead energy and was the first DR program to be integrated into the CAISO market. This case also established core functionalities that could be reused for future integrations where appropriate. The opportunity to integrate appropriate PG&E DR products into the CAISO Real-Time Market or as other CAISO products (i.e., AS) is addressed in the scope of the next phase of PDR which is referred to as PDR2. Cost recovery for this PDR1 infrastructure was submitted in the Market Redesign and Technology Upgrade (MRTU) proceedings.[5] PDR1 is the enabling foundation on which additional system changes will be built to integrate additional DR programs into the numerous CAISO products, services, and markets. For purposes of this discussion, the culmination of all technology elements will be referred to as the PDR platform. Any additional DR programs, CAISO products, services, or CAISO markets beyond what was delivered for PeakChoice day ahead energy as PDR represent additional scope that would require incremental effort and costs.

2. **Reliability Demand Response Resource Implementation:** The estimated costs of modifying PG&E's systems and processes to be able to integrate PG&E's Base Interruptible Program (BIP) into the CAISO's Real-Time Market (RTM) as RDRR.
3. **Electric Rule 24 Implementation:** Modifying PG&E's systems and processes to implement Electric Rule 24 to enable non-utility DR providers to integrate PG&E's bundled and non-bundled customers into

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3 PG&E had converted its PeakChoice program as a PDR to meet the Commission's goal of 10 percent of price responsive DR programs to be bid into the CAISO market, but that program no longer exists.

4 While Decision 12-04-045 ordered the closure of PeakChoice, the testimony will continue to refer to the program since this is the only program implemented in PDR1.

5 Application 09-06-001, filed June 1, 2009; Application 12-01-014, filed January 31, 2012; and Application 12-04-009, filed April 16, 2012.

the CAISO market. PG&E will be seeking approval of its proposed budget for Electric Rule 24 implementation in its June 2 application so no estimates are provided in this testimony.

4. **Implementation of Additional Market Integration Capability of PG&E's DR Programs:** The estimated costs to meet scope for PDR2. This includes the modification of PG&E's systems and processes to be able to integrate PG&E's DR programs, as appropriate, into the CAISO's RTM as PDR and AS products.

Conceptually speaking, a foundational technology-based platform is needed to migrate PG&E's DR programs into the CAISO market. This foundational platform is essentially an integrated set of information technology processes that coordinate business transactions within and between various PG&E business groups who play a role in the bidding, dispatch, and settlement of resources in the CAISO market or with PG&E's DR programs. Segments of this platform were delivered as part of PDR1. These segments support a set of core functions, portions of which can be reused for future PDR, RDRR, and Rule 24 phases as appropriate. The core functions supported are:

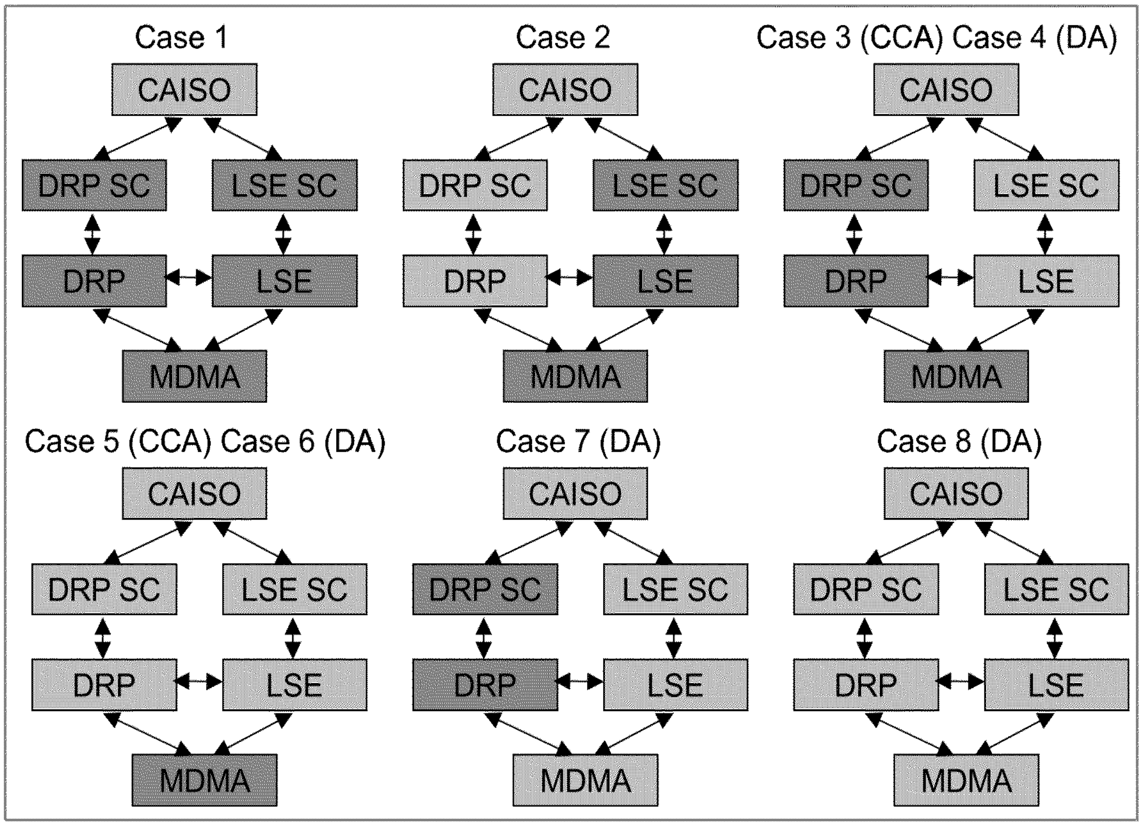
1. Create, submit, manage and terminate PDR registrations for PDRs consisting of PG&E's bundled customers.
2. Create, suspend, manage and retire PDR resources.
3. Assign and remove DR participants to and from PDR registrations.
4. Initiate a Business Process Management system that coordinates the tasks that PG&E must perform to establish a PDR registration and its associated PDR resource.
5. Register DR participants in the CAISO's DR System, which is the system that the CAISO developed for DRPs, LSEs, and Utility Distribution Companies to manage PDR participants and PDR resources.
6. Submit to the CAISO 45 days of historical hourly meter data aggregated to the PDR to support the CAISO's baseline calculations.
7. On an ongoing basis, submit to the CAISO hourly metering data aggregated to the PDR no later than five business days after any

demand reduction bid associated with the PDR clears the CAISO markets.

8. Set up the necessary metering systems to support the CAISO's requirement that hourly meter data aggregated to the PDR be submitted to the CAISO within five business days after the trade day.
9. Manage the DR participants, the PDR registrations and the PDR resources.

The complexity and cost of the platform is heavily driven by the number of role(s) necessary to integrate DR into the CAISO's wholesale market. The six major roles are the following: (1) DRP; (2) Utility Distribution Company; (3) LSE; (4) MDMA; (5) DRP's Scheduling Coordinator (SC); and (6) LSE's SC. As I discuss further below, PG&E currently has the capability of fulfilling all of these roles. However, certain roles (like DRP, LSE, SC and MDMA) can also be filled by third parties which introduces additional complications and costs as more transactions, communications, data, and data transfers become necessary to support increasing numbers of roles played by different parties and their interdependent relationships. These costs are in additional to what is incurred by the third parties for themselves to perform those roles. Certain common core functionality can be developed to service the needs of both PG&E and third parties. In the case where the DRP role is performed by a third party, support of their functions are described in the Rule 24 discussion. Figure 3-2 below illustrates the many different scenarios by role. Each scenario introduces additional complication and cost to building and operating the platform.

FIGURE 3-2
PACIFIC GAS AND ELECTRIC COMPANY
DIAGRAM OF DIFFERENT PDR SCENARIOS BY ROLE



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* Boxes in blue imply roles managed by PG&E and boxes in grey imply roles managed by third party. In each of the eight cases, PG&E is the Utility Distribution Company.

Once a platform is developed to link all of these departments, functions and parties, then incremental work must be done to enable individual DR programs to be bid and dispatched as energy and/or AS in the CAISO's IFM and/or RTM. The scope and therefore cost of this incremental work is closely based on the type(s) and number of energy resources the DR program will provide and whether the DR program will be bid in as a day-ahead energy resource, a real-time energy resource, or a resource that can provide one or more ancillary services such as spinning reserves and non-spinning reserves. The more resources that a DR program is enabled to provide in the CAISO market, the more information technology work required and therefore the higher the cost.

I now discuss the four infrastructure developments and costs in greater detail below.[6]

Proxy Demand Resource Implementation: Segments of this project were included in three of PG&E's MRTU applications,[7] and focused on building a portion of the information technology platform to create the foundation on which PG&E's DR programs can be migrated to PDR and RDRR.[8] This project constituted only Phase 1 of the deployment of the PDR platform in which PG&E fulfills the role as the DRP, LSE and MDMA, and the SC for both the LSE and the DRP. This work was referred to previously in this chapter as "PDR1." In Figure 3-2, this is depicted as Case 1. In addition to building the PDR platform that enables bidding PDR as energy into the IFM, this work also included the incremental work required to enable PG&E's PeakChoice program to bid as a PDR as energy into the IFM.

To implement PDR1, a set of core functions had to be enabled and supported. These core functions and their relationships with one another are shown in Figure 3-3.

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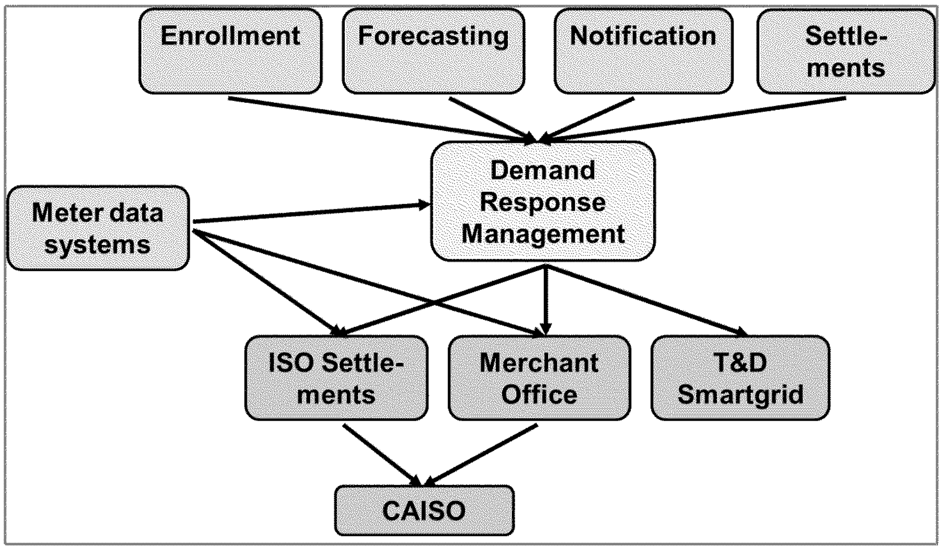
6 There may be other potential products in the CAISO market for which we have not estimated the cost of systems necessary to integrated into the CAISO market.

7 Application 09-06-001, filed June 1, 2009; Application 12-01-014, filed January 31, 2012; and Application 12-04-009, filed April 16, 2012.

8 The costs incurred are in PG&E's MRTU memorandum account, awaiting the Commission's final decision.

FIGURE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
CORE FUNCTIONS IN PDR1



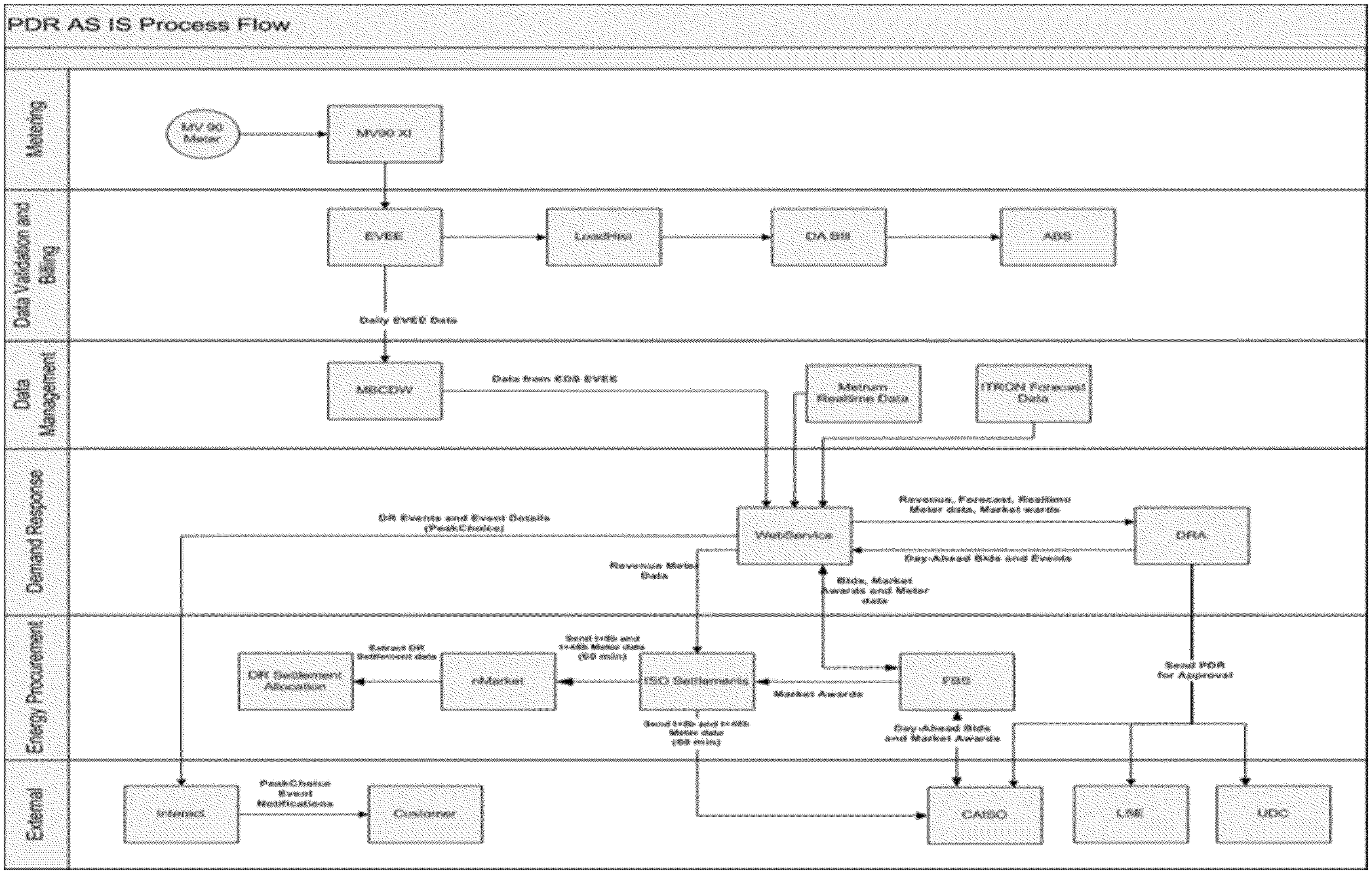
I now explain these core functions in greater detail. These core functions include:

- DR Management: Management of the DR programs, customer enrollments, and PDR resources.
- Enrollment: Management of the DR resource enrollments with the CAISO and with internal DR programs.
- Forecasting: Forecasting of load drops and event performance.
- Notification: Management in integration with different event notifications such as CAISO market awards notifications, and DRP resource and registration notifications.
- Settlements: Management of any PG&E DR program settlements.
- Meter Data Systems: Providing the CAISO with meter data associated with load reductions.
- ISO Settlements: Management of the shadow verification and settlement of the DR resources in the CAISO market.
- Bidding: Management of the DR CAISO bid submission and market awards from the CAISO systems.
- Transmission and Distribution (T&D): Alignment of all CAISO dispatches with T&D to allow for proper forecasting of system load and DR program capacity.

- CAISO: Integration and interface with the CAISO systems for all DR registration, settlements, bidding, and dispatch processes.

Figure 3-4 provides a high-level process flow for integrating PDR for day-ahead energy into PG&E's systems and processes. As I explained above, the scope of PDR1 was limited to enabling PG&E's DR programs to be bid only as day-ahead energy resources in the CAISO IFM, as well as migrating the PeakChoice program into the IFM.

FIGURE 3-4
PACIFIC GAS AND ELECTRIC COMPANY
PDR PROCESS FLOW



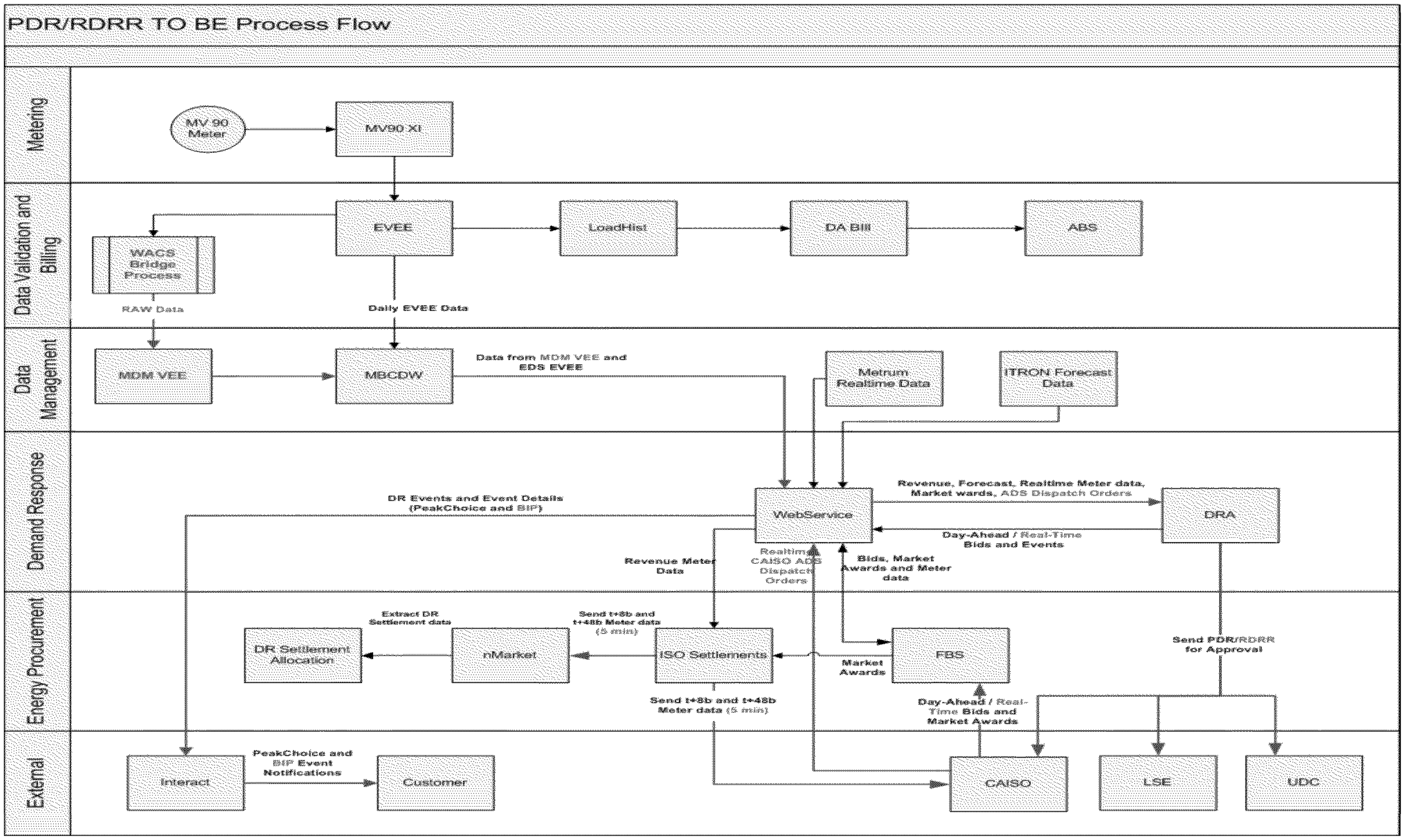
The total cost for the PDR1 implementation as described in some of PG&E's applications for MRTU cost recovery was for a total cost of $16.1 million as shown in Table 3-2.

TABLE 3-2
PACIFIC GAS AND ELECTRIC COMPANY
PDR1 COSTS RECOVERED THROUGH MRTU

Line No.	Operational Period	PDR Business Related (Expense)	PDR Information Technology Related (Capital)	MRTU Application
1	7/30/2008 – 12/31/2009	$196,109	–	A.09-06-001
2	1/1/2010 – 12/31/2010	181,725	$7,355,000	A.12-01-014
3	1/1/2011 – 12/31/2011	52,000	8,297,000	A.12-04-009
4	Totals	$429,834	$15,652,000	
5	Grand Total		$16,081,834	

RDRR Implementation: PG&E has not yet developed the RDRR platform but it would build on the functionality of the PDR1 platform described above. The added functionality would enable integration with the CAISO Real-Time Dispatch Automated Dispatch System as well as managing and executing the dispatch of PG&E's DR programs in real time. Just as the PDR1 platform created the foundation for PG&E to migrate its DR programs into the CAISO's IFM, these added functions will enable PG&E to bid its DR programs as energy into the CAISO's RTM as RDRR. This enhanced foundation would then be used to migrate PG&E's BIP as a RDRR into the RTM. Like the PDR1 platform, the RDRR platform will also enable the interface of all of the relevant internal PG&E departments as well as any external parties that may be involved. Where applicable, elements of the PDR1 platform will be reused to meet the RDRR functional requirements. Figure 3-5 provides a high-level process flow for integrating RDRR into PG&E's systems and processes to support bidding BIP as energy in the RTM.

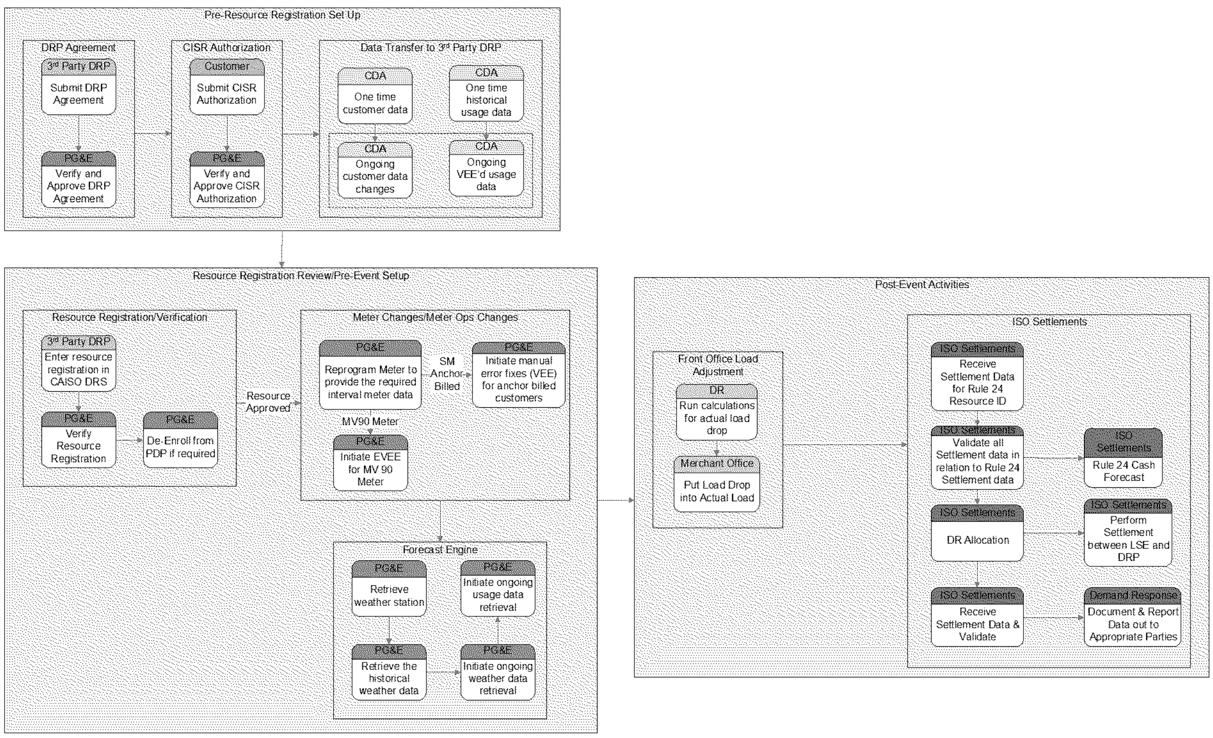
FIGURE 3-5
PACIFIC GAS AND ELECTRIC COMPANY
RDRR TO-BE PROCESS FLOW



PG&E has not yet requested authorization and cost recovery to move forward with this project, but PG&E estimates the cost of this project to be approximately $4 million-$5 million.

Electric Rule 24 Implementation: Implementing Electric Rule 24 will require an extension of PG&E systems to support the direct participation of third-party DRPs in the CAISO market using PG&E bundled and non-bundled customer retail load. This will require PG&E to support a number of processes involving DRP resource registration, meter data management, and integration to allow for appropriate adjustments to PG&E's load forecasting and LSE settlement processes to account for the third party DRP resources and dispatches. Figure 3-6 below provides a high level process flow for implementing Electric Rule 24.

FIGURE 3-6
PACIFIC GAS AND ELECTRIC COMPANY
ELECTRIC RULE 24 PROCESS FLOWS



PG&E will be submitting its final Electric Rule 24 implementation cost estimates in its June 2, 2014 application for funding and cost recovery. PG&E is currently developing its budget request and cannot provide an estimate at this time.

Implementation of Additional Market Integration Capability of PG&E's DR Programs: I have described the PDR1 project and associated costs to develop a platform for bidding PG&E's DR programs into the CAISO's IFM. I have also explained the project and estimated costs to develop a platform for bidding PG&E's BIP as RDRR through the CAISO RTM. However, there are many other "cases" for the incremental work to expand the PDR platform to enable bidding into the RTM and to provide AS, and to migrate specific PG&E DR programs into the CAISO market as PDRs as denoted in Figure 3-1 as PDR2. Similarly, there are many other use cases for the incremental work to expand the RDRR platform to enable bidding into the IFM and RTM as RDRRs. As described in Figure 3-1, I provided a matrix of the cases that PG&E has studied by PG&E DR programs, customer type, LSE, MDMA and DRP. The cases are labeled as being within the scope of either PDR1, PDR2, RDRR Implementation, or Electric Rule 24 Implementation (Rule 24). PG&E has not studied all possible cases, and in some instances a DR program is not suitable for some CAISO markets. As I indicated above, PDR1 has been completed and was funded through PG&E's MRTU applications. Funding for PDR Implementation Phase 2, RDRR Implementation, and Electric Rule 24 Implementation has not been requested and no work has been performed on these projects. PG&E will be requesting funding for Electric Rule 24 Implementation in its June 2, 2014 application.

The PDR1 Implementation case is denoted as Case 1a. As I explained above, the scope of this project was to build the PDR platform for enabling the bidding of PG&E's DR programs as energy into the IFM, and to migrate PG&E's PeakChoice program into the IFM for energy as a PDR. PDR2 implementation cases are denoted for the designed markets and products for Cases 1a through 1d, 3a through 3b, 4a through 4b, and 7a through 7b. The PDR2 scope includes the integration of PG&E's Capacity Bidding Program (CBP), Aggregator Managed Portfolio (AMP) Program, and SmartAC programs into the CAISO's IFM for energy.

The RDRR Implementation case is denoted as Cases 1e, 3c, 4c and 7c. In addition to building the RDRR platform, the scope of this project includes the ability to offer PG&E's BIP in the RTM as RDRR for Real Time Energy.

Electric Rule 24 Implementation cases are denoted as Cases 2, 5, 6 and 8. The scope of this project includes implementing Electric Rule 24 requirements that support the use by third-party DRPs of PG&E's bundled and non-bundled customers to participate in the CAISO's IFM, RTM and AS markets.

PG&E has previously developed one-time cost estimates of implementing some cases from PDR2 implementation that have been updated as shown in Figure 3-1 as well as foundational elements needed to support cases not shown in Figure 3-1. PG&E assumed a strict sequence of actions in estimating additional PG&E program participation based on best available data at the specific point in time. The estimated costs for a program cannot be viewed in isolation, due to costs associated with scaling and common platforms made in earlier implementations, which reduces subsequent program costs. As discussed earlier, in the initial description of Figure 3-1, these costs are only representative of the delivery of the information technology assets. These cost estimates as mapped to the Figure 3-1 case matrix are shown in Table 3-3 below.

TABLE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
PRELIMINARY ESTIMATED COSTS FOR SELECTED CASES FOR PDR2

Line No.	Name/Short Description	Cases	Estimated Cost
1	Convert CBP for PDR Day Ahead Energy	1b, 3a, 4a, 7a	~ $3M – $5M
2	Convert SmartAC for PDR Day Ahead Energy	1d	~ $7M – $8M
3	Convert AMP for PDR Day Ahead Energy	1c, 3b, 4b, 7b	~$1M – $2M
4	Expand PDR platform to enable Real Time Energy	Foundational	~$1M – $4M
5	Convert SmartAC for PDR Real Time Energy	1d	~$1M – $2M
6	Expand PDR platform to enable ancillary services (excludes telemetry)	Foundational	~ $2M – $4M
7	Total Estimated Range		~$15M to ~$25M

Without PDR2 Implementation, PG&E would be unable to support a large scale deployment of PDR as defined by the PDR2 Implementation scope. In Chapter 4 of PG&E's prepared testimony, Mr. Kenneth E. Abreu discusses PG&E's plans to utilize a manual process of bidding a limited number of CBP and AMP resources as PDR in the IFM beginning in 2014.

Q 3 Please provide a range of costs that they would consider to be reasonable. Explain why this range of costs is reasonable and costs outside the range are not reasonable.

A 3 I cannot opine as to whether the range of costs I have presented is reasonable relative to the incremental benefits that may result. The Commission should focus instead on the overall cost effectiveness of integrating DR into the CAISO market. I refer to the Chapter 1 testimony by PG&E witness Mr. Nicholas K. Ho and the Chapter 4 testimony by PG&E witness Mr. Kenneth E. Abreu regarding the relationship of cost effectiveness to market integration costs.

Q 4 For costs outside the range and therefore unreasonable, please provide examples of ways to decrease those costs.

A 4 I refer to the testimony of Olivine witness Mr. Spence Gerber and the testimony of Dr. Alex Papalexopoulos of Electric Control Center Operations International (both testifying on behalf of PG&E) regarding potential ways to reduce market integration costs.

Q 5 In its December 13, 2013 filing (p. 13), PG&E provided a list of solutions for decreasing CAISO market integration costs. Do you have any additional comments on this list of solutions?

A 5 No. Please refer to PG&E's comments in response to Question 4 above.

D. Conclusion

Q 6 Does this conclude PG&E's testimony on CAISO Market Integration Costs in Attachment A to the ACR?

A 6 Yes, it does.

PACIFIC GAS AND ELEC TRIC COMPANY

CHAPTER 4

SUPPLY RESOURCES

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
SUPPLY RESOURCES

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
SUPPLY RESOURCES

A. Summary

- The characteristics for utility Demand Response (DR) programs or parts of programs to be Supply Resources DR should be:
  1. A DR program that provides a product that the California Independent System Operator (CAISO) directly procures (e.g., ancillary services, etc.); or
  2. Any DR program or part of a DR program where the incremental benefits of bidding DR as supply exceed the incremental costs of bidding DR as supply.
- No current Pacific Gas and Electric Company (PG&E) DR program has these characteristics.
- However, in recognition of the California Public Utilities Commission's (CPUC or Commission) desire to see more DR integrated as Proxy Demand Resources (PDR), PG&E is committed to integrating approximately 10-20 megawatts (MW) of DR as Supply Resource DR in 2014 and potentially more in 2015 and 2016. This is a feasible and practical level that can be done without major cost commitments or program changes.
- The Demand Response Auction Mechanism (DRAM) is one possible way to increase the amount of cost-effective DR, but the proposal is complex and needs further examination of its effectiveness before it might be adopted.
  – Ensuring a wide range of DR program and procurement options, in addition to a proposed DRAM, will promote customer participation and maximize the amount of cost-effective DR.
  – Procurement mechanisms for DR should encourage a wide range of customer types to participate in DR programs.

B. Introduction

Q 1 Please state your name and the purpose of your testimony.

A 1 My name is Kenneth E. Abreu and the purpose of my testimony is to respond to questions related to Supply Resource Issues that were included in Attachment A to the April 2, 2014 Joint Assigned Commissioner Ruling

(ACR) revising scope and schedule for the 2013 DR rulemaking Phases 2 and 3.[1] My qualifications are included in Exhibit (PG&E-1).

C. Responses to ACR Supply Resource Questions

Q 2 Parties requested the Commission to analyze the characteristics of each DR program in order to categorize current and future DR programs into load modifying resources and supply resources. Please provide your list of characteristics that the Commission should use in determining how to categorize a supply resource.

A 2 PG&E proposes that the following characteristics should be used to categorize utility DR programs as Supply Resources:

1. Any DR program that provides a product that the CAISO <u>directly procures</u> (e.g., ancillary services, etc.); or
2. Any DR program or part of a DR program where the incremental benefits of bidding DR as supply exceed the incremental costs of bidding DR as supply.

The first characteristic applies to DR products that the CAISO directly procures. These are primarily ancillary services. Products that the CAISO specifies, procures and uses for its own balancing authority functions need to meet the full requirements of the CAISO. This does <u>not</u> apply to DR bid into the CAISO energy markets or to investor-owned utility (IOU) DR programs that the CAISO may call on for reliability purposes and that are not ancillary services.

The second characteristic protects ratepayers from paying the incremental cost of bidding a DR program into the CAISO market if there are no net incremental benefits to ratepayers.

As a point of information, Supply Resource DR will also be provided by third parties (non-IOUs). If a DR provider wants to directly participate in the CAISO market and it is not the Load Serving Entity (LSE) for retail customers, then bidding in as Supply Resource DR is the only mechanism to participate. This was one of the primary reasons for the creation of PDR,

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1 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings.

so that non-LSEs could bid DR directly into the CAISO markets (see Exhibit (PG&E-1), Appendix B, A-14).

Whether the DR is called a "Supply Resource" or a "Load Modifier Resource", however, no one should ignore that what is happening is shifting or reducing customer load behind the meter for time periods for which the customer's load reduction is called.

Q 3 Using your proposed list of characteristics, describe each demand response program and determine whether that program should be classified as a supply resource, as defined by Decision 14-03-026. Using your list of characteristics, describe how and whether subsets of customers in existing programs could be sub-aggregated and classified as Supply Resources.

A 3 Using the list of characteristics provided in Answer 2 above, none of PG&E's existing programs or subsets of existing programs should be classified as Supply Resource DR. This finding is based on the fact that none of PG&E's current DR programs are designed to provide a product that the CAISO directly procures and thus none of them meet the first characteristic. Furthermore, the incremental costs of converting them to Supply Resource DR outweigh the incremental benefits of doing so. There are currently significant upfront and ongoing costs associated with integrating PG&E's DR programs as Supply Resource DR into the CAISO market. This is supported by the testimony of PG&E witness Stephen Kung in Chapter 3, PG&E witness Dr. Alex Papalexopoulos of ECCO International in Appendix A, PG&E witness Spence Gerber of Olivine in Appendix B and PG&E witness Dr. Jay Zarnikau of Energy & Environmental Economics (E3) in Appendix C. And there is little or no incremental benefit to integrate PG&E's existing DR programs as Supply Resource DR in the CAISO market, as supported by Dr. Alex Papalexopoulos in Appendix A and Dr. Jay Zarnikau in Appendix C. Thus, there is no existing PG&E DR program or subsets of a program that would appear to have the second characteristic of the incremental benefits exceeding the incremental costs of integrating as Supply Resource DR.

However, in recognition of the expressed desire of the Commission and CAISO to have more DR bid into the CAISO market as Supply Resource DR, PG&E has committed to integrating approximately 10-20 MW of its DR, consisting of subsets of its Capacity Bidding Program (CBP) and Aggregator Managed Portfolio (AMP) Program, as Supply Resource DR in 2014 and will increase that amount in 2015 and 2016 to the extent it is feasible and practical to do so. An analysis of each DR program and its feasibility as Supply Resource DR is provided in Exhibit (PG&E-1), Appendix B (by Mr. Spence Gerber of Olivine, Inc.). Mr. Gerber's testimony shows that, at least initially, only a small part of PG&E's existing programs can feasibly and practically be bid in the CAISO market as Supply Resource DR. PG&E does not see that this effort to integrate 10-20 MW of existing DR in the CAISO market meets the characteristic of incremental benefits exceeding incremental costs (the second criterion described in Answer 2 above). But the intent of this effort is to integrate DR as Supply Resource DR at a level that does not incur major cost commitments or programmatic changes. This effort will involve manual bidding of parts of its CBP and AMP program as PDR in 2014 in order to gain some additional knowledge and experience. This commitment goes beyond the Intermittent Renewables Management 2 (IRM2) Pilot program in which PG&E is already bidding in DR as a Supply Resource. The experience gained through this bidding in 2014 and 2015 will inform future program design and funding for larger scale integration of Supply Resource DR in the CAISO market. Should the Commission decide in Phase 3 or 4 of this proceeding that more DR should be integrated as Supply Resource DR, PG&E will seek that additional funding in the next DR program funding application (November 2015 filing for 2017 and beyond).

It is important to note that the second characteristic may be met over time as barriers in the CAISO market are reduced, DR programs are improved, the experience gained from bidding DR grows, new Information Technology systems are deployed, and opportunities to reduce costs are identified and implemented. This will require a transition over time. Several potential opportunities to reduce the costs and complexity of bidding DR in the CAISO market have been identified, and experts are of the opinion that these opportunities exist (see Exhibit (PG&E-1), Appendices A and B). However, the transition of more DR programs to Supply Resource DR will take a significant amount of time (see Exhibit (PG&E-1), Appendices A and B).

PG&E has had DR programs in the past that would have been characterized as Supply Resource DR. PG&E had a program, PeakChoice™, that was successfully bid and dispatched in the CAISO's day-ahead energy market as Supply Resource DR, but the program was not approved for continuation by the Commission beyond 2012. This program was also going to have an ancillary service feature added to it that was intended to meet the requirement of Decision 09-08-027, Ordering Paragraph 26 for a DR program capable of providing ancillary services. PG&E's IRM2 Pilot was kicked off in 2014 and is bid in as Supply Resource DR. PG&E has also proposed a Supply Side Pilot for the 2015-2016 Bridge Period that would be bid in as Supply Resource DR (if approved by the Commission in Phase One of this proceeding).

Q 4 In the April 2, 2014 ACR (Attachment A, p. 2), parties were invited to provide their overall comments on the DRAM proposal provided in Attachment B. Does PG&E have overall comments regarding the DRAM?

A 4 Yes. PG&E's overall comments on the proposed DRAM are given below, followed by responses to the additional questions.

The Commission proposal for the DRAM in Attachment B is a good starting point for developing an auction mechanism for DR; it is clear that significant thought went into the proposal.

PG&E believes reverse auctions work reasonably well for markets in which there are homogeneous products (like the three buckets used in the Renewable Auction Mechanism (RAM)), and little additional need to consider other values a product type brings. Such a market with streamlined processes (e.g., without negotiable terms and a simple valuation approach where offers can be selected based on price) can lessen the burden put on the evaluation process. However, standardizing DR products may not be the most effective method to procure all DR at this stage given the difficulties to develop standardized products and valuation methods. Opportunities might be lost if cost-effective Supply Resource DR does not meet the requirements of the standardized products that would be solicited in the DRAM, or if all of the value streams that different types of DR bring to the table are not fully considered in the auction process.

The DRAM proposal has several positive features, including:

- The ability to frequently (at least once per year) seek new contracts
- 60 days for Commission approval of contracts
- The use of competitive procurement
- The rules to prevent double procurement appear to be robust
- One year from Commission contract approval to delivery of MW is appropriate

However, the DRAM proposal raises some significant concerns:

- On pages 2 and 7 of the proposal, it seems to imply that DRAM will be the single tool to reach a 5 percent DR goal by 2020. This seems to prejudge that the DRAM is the exclusive tool to increase Supply Resource DR without showing that it is more effective than a Request for Proposal (RFP) or IOU tariff-based program. PG&E witness Nicholas K. Ho presents additional ideas for increasing the amount of DR in Chapter 1, Answer 3.
- The DRAM also focuses exclusively on Supply Resource DR and seems to assume that only Supply Resource DR will be used to reach any new DR MW goal (ACR, Attachment B, pp. 2, 3, 4 and 7). Any DR MW goal should include both Load Modifying Resource DR and Supply Resource DR. Both Supply Resource and Load Modifying Resource DR can be price responsive and so both should count toward any DR goal for price responsive DR.
- The utility procurement obligation (p.7 of proposal) would create a preset goal for DR MW of 5 percent of peak load by 2020. This prejudges one of the main topics of this proceeding which is to examine what a reasonable goal for DR might be (see ACR, p. 4). PG&E presents an alternative goal and process to meet that goal for DR in Chapter 1. PG&E's alternative is focused on implementing an action plan that creates the maximum amount of cost-effective DR.
- The Capacity Cost Cap concept (p. 6-7) should not be used. Instead, the DR cost-effectiveness protocols should have its deficiencies fixed and then it should be used.

- As the Commission proposes, the DRAM would have a cost cap calculated based on the average of bids received for those resources, for the separate price responsive demand and emergency triggered DR resources. PG&E is concerned that such a cap may have unintended consequences. First, since the cap is designed to be based on actual bids, the process could create perverse incentives for some participants to submit high bids for the purpose of raising the cap unless properly monitored. Second, since the cap is based on the average of the bids received, approximately halfof the offers would be automatically identified as not being cost effective without any other evaluation of the relative value the projects bring to the market.
- This problem is further exacerbated by the absence of a developed Supply Resource DR market. No party knows how much DR is available that can meet the requirements of the DRAM so the DRAM auctions could be extremely illiquid. In other words, there may be very few offers in the auctions, which would significantly limit the DRAM's effectiveness in promoting efficient price discovery.
- This second unintended consequence could lead to the IOUs not taking DR MW that is cost effective since they might fall above the average of the bids received. Alternatively, it could lead to taking DR MW that are not cost effective since they are less than the average of the bids that define the cost cap even though, with the traditional Commission cost-effectiveness criteria they are not cost effective.
- The schedule for the DRAM is very aggressive and will limit the amount of DR MW that is offered. The DRAM is a new, complex proposal. More time and process review are needed to enable all stakeholders to understand the proposal and work to improve and implement it.

• The DRAM would benefit from careful consideration of its objectives and its processes. It should be tested in an initial trial and the lessons learned applied to improve it.
• DRAM is only one of several ways to capture more DR.

- The RAM, on which the DRAM is modeled, was used for a limited portion of the Renewable Portfolio Standard procurement.
- DR MW will potentially be lost if the DRAM is the exclusive mechanism for growing DR. DR that does not fit into the standardized products will simply be lost because there will be no other way for it to participate.
- Lost DR MW will also represent missed opportunities for innovation. If only standardized products are procured, this will limit the resources that market participants devote to other valuable applications of DR. The lost value from inhibiting innovation may be considerable (see Exhibit (PG&E-1), Volume 2, Appendix C). Multiple paths for procuring a range of DR products must be pursued so as to maximize the amount of cost-effective DR and to spur innovation in DR.
- The IOUs have achieved great results by procuring DR using RFPs. This approach allows for contracts of a range of Load Modifying Resource DR and Supply Resource DR products of different durations. PG&E would want to be able to seek competitively bid contracts for Supply Resources where there are different criteria than are identified in the DRAM proposal. For example, contacts with a long term (5 years) and with a longer amount of time for bid preparation, contract negotiations and for implementation should be permitted. This could lead to more DR MW for more products.

Q 5 Does PG&E have responses to the ACR's additional questions (ACR, Attachment A, pp. 2-4) regarding DRAM?

A 5 Yes. The responses that follow respond to the additional questions related to the DRAM in the ACR (Attachment A, pp. 2-4).

Q 6 Are the proposed contract durations of one, two or three years sufficient? Should contracts of a longer duration be included? Why or why not? If yes, what duration(s) is/are recommended?

A 6 A robust portfolio of DR resources will contain contracts of various durations to capture the maximum value and manage the risk of having all contracts expire at the same time. PG&E has found that the maximum contact length of five years is reasonable to assure DR providers that they have a long-term commitment on which to build a business. This was the duration of the original AMP contacts and allowed several aggregators to establish a strong foothold in California. So, for a new part of a DR portfolio a term of five years is likely needed. On the other end of the spectrum, the CBP only requires a 1-month commitment. Because of the short commitment period, this program has proven useful for aggregators to test out new customers for potential migration to their AMP contracts and to try out the California market without having to make a major commitment.

The range of one to three years in the DRAM proposal is "in-between" the time commitments described above and are reasonable time frames to have for some portion of the DR portfolio. However, DRAM should not be the exclusive way that DR is procured and other contract durations may be used in other DR procurement processes so as to better capture all cost effective DR.

Q 7 In addition to the elements listed in this DRAM proposal, are there provisions that should be included in a standard contract? Explain the reason for each recommended provision.

A 7 The current AMP contracts are a good start to any new standard contracts. It is premature to go into more details on DRAM contracts since more time and analysis are needed to understand and develop the proposal, in connection with the Commission's decision(s) on the future for DR.

Q 8 Are there benefits or drawbacks to holding one auction per year for seasonal products (May-Oct; Nov-Apr)? Describe these benefits and drawbacks. How should seasonal products be defined and structured, so as to maximize the potential of demand response in these seasons? If a different approach is preferable, describe in detail.

A 8 As described in PG&E's introductory comments on the DRAM, more discussion is needed before finalizing any DRAM and setting its frequency. Also, PG&E does not see the DRAM as the only competitive procurement method for DR, just as the RAM is not the only competitive procurement method for renewables. The RAM was only used to procure a limited part of the renewable portfolio. Thus, utilities should have the flexibility to procure as frequently as needed with DRAM and non-DRAM RFOs, so as to maximize the amount and types of cost-effective DR that can be procured.

Q 9 The proposed auction schedule is detailed in Attachment B. Provide any comments on the schedule, in recognition of the following desired parameters: (a) maximum of six months from RFO issuance to Commission approval; (b) up to 60 days for bid selection and contract signing; (c) 60 days for Commission review and approval of contracts; and (d) alignment with annual resource adequacy showings in October.

A 9 As described in PG&E's introductory comments on the DRAM, more discussion is needed before finalizing any DRAM and setting an auction schedule. However, I provide some initial observations on this schedule. The proposed timelines are very tight when compared to past AMP auctions. The schedule for the DRAM (ACR, Attachment B, Appendix 1) indicated ~4 months from RFO issuance to Commission approval which is different than the six months mentioned in Question 9. The last AMP RFO took seven months to accomplish those steps (even with a compressed, expedited regulatory schedule). Also, if the DRAM is intended to be for the purpose of procuring Supply Resource DR, the time for bidding may need to be much longer. This is because the added complexity of developing bids for Supply Resource DR may necessitate more time for DR providers to develop their bids. An indication of this need for more time is the slow rate of participation in the IRM2 pilot, where third parties have been slow to participate in spite of very favorable capacity payments and "free" bidding infrastructure (see Exhibit (PG&E-1), Appendix B). This indicates that any DRAM for Supply Resources DR is likely to need significant time for bidding. Also, the Commission should consider that the first time any DRAM is held, due to DR providers' unfamiliarity with it, a learning period should be expected.

Another important consideration is how long it will take to develop the DRAM process for the first auctions. The schedule in Attachment B assumes this process will take about 12 months from Energy Division proposal to first auction. This is a very short time based on the experience of the RAM. The RAM process took ~27 months from the time the Commission issued a Ruling with an Energy Division recommendation for a pricing proposal for RAM (August 2009) to when the first RFO was issued (November 2011). This process included a Decision (D.10-12-048) that approved the RAM that was followed by rounds of comments to refine the standard contracts and the process in a Resolution (Res E-4414 – August 2011). While the many lessons from the RAM can be applied to the development of the DRAM, they are two very different products. The Commission should plan for somewhat comparable time to develop a DRAM.

Q 10 Is it preferable to have additional minimum eligibility criteria for bids than those listed in this proposal? Please fully describe the recommended criteria and how it should be used to judge bid viability.

A 10 As described in PG&E's introductory comments on the DRAM, more discussion is needed before finalizing any DRAM and setting the eligibility criteria.

Q 11 The proposal is to base the capacity cost cap for each auction on the average of bids received, per auction. Are there additional factors that should be considered in constructing a capacity cost cap? Is a different approach preferable? Please describe any recommendations in detail.

A 11 The cost cap proposal in the DRAM proposal seems arbitrary and could lead either to cost effective DR not being taken or conversely, to taking DR that is not cost effective. Instead of using the proposed cost cap approach it would be preferable to use the existing DR cost effectiveness protocols after fixing the identified deficiencies to determine winning bids. As PG&E witness Nicholas K. Ho discusses in Chapter 1, the DR cost-effectiveness protocols should reflect the qualitative and quantitative values of such attributes as CAISO market integration, ramping, fast response, etc.

Q 12 Emergency demand response resources are included in the DRAM, which means that these resources must receive their capacity payments via a competitive mechanism. Provide specific recommendations on this approach.

A 12 The pure emergency programs should be considered for the DRAM only after more experience is gained with the DRAM. The Base Interruptible Program (BIP), which is PG&E's one pure emergency DR program, is bridged for the period 2015-2016. The BIP operates well now, but if the customers migrate to the DRAM in the bridge period, their performance could be affected by the transition, and the costs for their DR could increase as they may seek higher payments in the DRAM than they now receive in the BIP. Also it seems that DRAM is primarily intended to encourage price responsive DR to bid into the CAISO market as a Supply Resource. Pure emergency programs are only used in emergencies and are not price responsive. Expanding them to be price responsive DR supply resources may lead to them not being available when needed to alleviate emergency conditions or may reduce enrollment. The non-emergency DRAM DR, however, would be price responsive and should also function to reduce load to contribute to balancing the system, and would promote reliability and stability of the grid by managing load, especially when the system approaches stressed conditions and/or is accommodating significant amounts of intermittent renewable resources.

Q 13 This proposal contains the option for the Commission to publish a weighted average of bids received at some point following each auction. Are there competitive, or any other, concerns with this action, should the Commission choose to adopt it? Describe in detail. If another approach or calculation is preferable, describe the recommendation in detail.

A 13 The Commission should not publish any bid price information. This is competitive information and should not be released. The RAM process did not publish this type of information, nor should DRAM.

Q 14 The proposal notes that penalties may apply if deliveries of the demand response resource fall below 60 percent of contracted capacity. Comment on the appropriateness of penalties in addition to capacity derates, and the point at which penalties could or should apply.

A 14 As described in PG&E's introductory comments on the DRAM, more discussion is needed before finalizing any DRAM and the possible penalty structure. The current PG&E CBP and AMP programs have penalties when deliveries are below 60 percent. So the DRAM proposal (60%) is consistent with the current CBP and AMP program. However, the DRAM contract needs to be viewed as a whole and this may or may not be the correct number for the final DRAM contract. PG&E recommends that the most recent changes to the CBP and AMP program contain several features that serve as a reasonable starting point for a standard DRAM contract.

Q 15 This proposal currently envisions Commission-regulated utilities procuring DRAM capacity on behalf of their own load, and does not include a procurement obligation for other LSEs. Comment on whether other LSEs should also have a procurement obligation for DRAM capacity and, if so, how such procurement should be structured. Be as specific as possible.

A 15 There is no need to require other LSEs to have a procurement obligation, as long as the DR Auction Mechanism costs continue to be recovered from all electric customers through distribution rates as most DR incentive and program costs currently are (see Chapter 8, Table 8-1). As discussed in Chapter 8 (Cost Recovery), DR program costs—including DR Auction Mechanism capacity costs—are appropriately recovered via distribution rates (see Chapter 8, Section B).

Q 16 In Decision 14-03-026, the Commission discusses its policy of increasing the amount of demand response integrated into the CAISO market. How can the Commission determine an appropriate annual goal for overall demand response integrated into the CAISO market? Are there terms that we need to identify and define? What should those terms and definitions be?

A 16 PG&E responds to this question in the testimony of PG&E witness Nicholas K. Ho in Chapter 1 on Goals.

Q 17 How should the Commission improve forecasting with regard to supply resources that will be integrated into the CAISO energy markets? What are methods to improve the forecasting? What are methods that the Commission can use to modify current demand response programs to meet forecasted needs? What are methods that the Commission can use to design new programs to meet forecasting needs?

A 17 The Commission should encourage the IOUs to continue to improve all aspects of their DR forecasting (*ex ante* or operational) regardless of whether the DR is a Supply Resource or a Load Modifying Resource. It is up to the IOUs (working with the Demand Response Measurement and Evaluation Committee, or DRMEC) to develop the forecasting methods and DR programs that work best for their operations and planning. These can be included in the plans that the IOUs submit in their DR Budget applications (next to be filed in November 2015).

Q 18 Decision 12-04-045 discussed the future of demand response and questioned what the roles of the utilities and third-party providers would be in administering future programs. Please provide your comments on whether a utility centric model for supply resource demand response can meet current and future needs. Provide your comments on the ability of third-party providers to provide supply resource demand response to meet current and future needs. As discussed in Decision 12-04-045, should the Utilities continue to offer rate regulated supply resource demand response if these services are provided through competitive markets? Should the Commission focus on identifying more of these programs as supply resources, thus facilitating broader competition in the market? Should the utilities' role be solely to oversee the competitive procurement?

A 18 The Commission should keep fully open the opportunities for <u>all</u> parties to provide DR programs so that the full amount of cost-effective DR can be captured. This means that IOUs should continue to have DR programs and IOUs should continue to be able to contract with aggregators and customers for DR. It also means that aggregators, customers and other LSEs should have the flexibility to create and implement their own DR programs as well. The aggregators, customers and LSEs may wish to bid their DR into the CAISO market as supply or they may choose to handle the DR as a load modifier. Each of these entities brings unique abilities and interests to DR and to "pick a winner" is most likely to reduce the amount of cost effective DR that could otherwise be captured. See PG&E comments on Goals in Chapter 1, which further explains how a full range of options should be kept open so that cost-effective DR can be maximized.

IOUs have several characteristics that make it appropriate for them to continue to provide DR through rates, tariffs and contracts. IOUs are LSEs and as such they will have rates. Providing their customers DR options as part of their rate offerings is an efficient way to capture DR. IOUs also offer energy efficiency and other products, and it is efficient to offer DR as part of an integrated approach to customers. IOUs also own and operate the distribution systems, own the transmission systems, and participate in transmission planning (together, T&D), so incorporating DR into T&D planning and operations is a unique opportunity to capture cost-effective

DR. IOUs are also procuring supply-side resources to meet their LSE obligations and having DR as a tool in the portfolio will allow a more robust portfolio.

The Commission should not "focus on identifying more of these programs as supply resources," but should allow utilities, aggregators and customers the flexibility to decide how best to capture the value of DR.

The IOUs' role in competitively procuring DR should be analogous to their role in procuring generation resources. The utilities currently conduct the procurement of generation and manage the contracts, and they should similarly be able to do the same for DR.

Q 19 For supply resources integrated into energy markets without a capacity contract, does the Commission have any role in tracking the resources' load impacts? If yes, how should the load impacts of these resources be tracked and accounted?

A 19 If the question is referring to Supply Resource DR that non-IOUs bid into the CAISO energy markets and where the non-IOU has no capacity contract with an IOU, then the Commission will need some way to track these load impacts as well. PG&E recommends that the Commission consider having these third party DR providers use the Load Impact Protocols (D.08-04-050) and processes to track these resources to ensure that non-IOU resources impacts can be evaluated in a comparable basis with IOU ones.

D. Conclusion

Q 20 Does this conclude your testimony?

A 20 Yes, it does.

PACIFIC GAS AND ELEC TRIC COMPANY

CHAPTER 5

LOAD MODIFYING RESOU RCES

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A. Summary

- Load Modifying Resources should be the category for Demand Response (DR) programs that do not fit the characteristics of Supply Resource DR.
- Load Modifying Resources are less complex and costly than making DR into Supply Resources.
- Load Modifier Resource DR can provide similar value as Supply Resource DR.
- Load Modifier Resource DR can work well in a wholesale market.
  - DR as a load modifier will contribute to wholesale market price formation.
  - DR in other organized wholesale markets is equivalent to Load Modifier Resource DR, and these markets work reasonably well.
- Changes can be made to the California Independent System Operator (CAISO) processes to better coordinate Load Modifier Resources with the CAISO market.

B. Introduction

Q 1 Please state your name and the purpose of your testimony.

A 1 My name is Kenneth E. Abreu, and the purpose of my testimony is to respond to questions on Load Modifying Resource Issues that were included in Attachment A to the April 2, 2014 Joint Assigned Commissioner Ruling (ACR) revising scope and schedule for the 2013 DR rulemaking Phases 2 and 3 in Rulemaking 13-09-011.[1] My qualifications are included in Exhibit (PG&E-1).

C. Responses to ACR Load Modifying Resource Questions

Q 2 Parties requested the California Public Utilities Commission (CPUC or Commission) to analyze the characteristics of each DR program in order to

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1 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings.

categorize current and future demand response programs into load modifying resources and supply resources. Please provide your list of characteristics that the Commission should use in determining how to categorize a Load Modifying Resource.

A 2 In Pacific Gas and Electric Company's (PG&E) response Answer 2, in Chapter 4, Supply Resources Issues, two characteristics were proposed for DR to be a Supply Resource. Demand response should be categorized as Load Modifying Resource DR if it does not meet at least one of those characteristics. Load Modifying Resource DR should be the category for DR programs that do not fit the characteristics of Supply Resource DR. Since DR is actually a load modification, this is the simplest way to recognize its value and impact on the CAISO markets. Retaining a simple and authentic way for DR to impact the CAISO market by reducing demand is likely to provide more opportunity for new and innovative DR products, since the complexity and cost of bidding as Supply Resource DR would not be an inhibition to creating new and innovative products (See Testimony of Dr. Zarnikau and Dr. Papalexopoulos (Exhibit (PG&E-1), Appendices C and A) that Load Modifying Resource DR is less costly and complex than Supply Resource DR, that its value is similar and that it can work well in a wholesale market.)

Q 3 Using PG&E's proposed list of characteristics, please describe each DR program and determine whether that program should be classified as a supply resource, as defined by Decision 14-03-026. In addition, please describe how and whether subsets of customers in existing programs could be sub-aggregated and classified as Load Modifying Resources.

A 3 For now, all of PG&E's existing DR programs and subsets of programs would be categorized as Load Modifying Resource DR. See response Answer 3 in Chapter 4, Supply Resource Issues, for a description of how it was determined that none of the DR programs and subsets of programs should be classified as Supply Resources. Thus, based on the characteristic described in Answer 2 above, the programs should all be classified as Load Modifying Resource DR.

There is no identified significant benefit to having most DR as a Supply Resource DR rather than Load Modifying Resource DR. It is demonstrated in the testimony of Dr. Zarnikau (Exhibit (PG&E-1), Appendix C) that Load Modifying Resource DR can work well in the wholesale market, can have similar value to Supply Resource DR and that requirements to force DR to be Supply Resource DR could discourage DR participation.

The testimony of Dr. Papalexopoulos (Exhibit (PG&E-1), Appendix A) demonstrates that Load Modifying Resource DR can work well in the CAISO market and that improvements may be possible to make it work even better. The testimony of Mr. Gerber (Exhibit (PG&E-1), Appendix B) demonstrates that much of PG&E's DR portfolio cannot now be bid as Supply Resource DR and thus must be categorized as Load Modifying Resource DR if it is to be retained.

The current state of affairs, where all PG&E's programs are categorized as Load Modifying Resource DR, may change in the future if some programs or parts of programs were cost effective to bid as Supply Resource DR. Also, over time as the CAISO market evolves and barriers are reduced, DR programs are revised, Information Technology systems for DR bidding mature and more bidding experience is gained, it is expected that more DR will be bid as Supply Resource DR. Both the testimony of Dr. Papalexopoulos (Exhibit (PG&E-1), Appendix A) and Mr. Gerber (Exhibit (PG&E-1), Appendix B) identify ways that the cost and complexity of Supply Resource DR may be reduced, thus leading to the possibility of more Supply Resource DR in the future after changes are made.

Q 4 How can the Commission improve current programs designated as load modifying resources in order to meet forecasted needs? Does the Commission need to improve forecasting for Load Modifying Resources? How?

A 4 There are two types of DR forecasts the investor-owned utilities (IOU) produce: (i) *ex ante* load impacts filed April 1 each year; and (ii) a day-ahead operational forecast provided to CAISO. The two forecasts serve fundamentally different purposes where the former is a long-term forecast typically used for resource planning purposes while the latter is for short-term needs. It is not clear which type of forecast the question refers to. In either case, the Demand Response Measurement and Evaluation

Committee would be the proper venue to address the issues, given its expertise for technical evaluation issues.

With regards to forecasting, the IOUs should be responsible for continuing to improve their *ex ante* and operational forecasting for their DR programs (both Load Modifying and Supply Resources). The Commission can monitor this through the various DR forecasting and reporting processes already in place (e.g., Annual Load Impact filings, forecasts to CAISO when DR is called, etc.).

The testimony of Dr. Papalexopoulos (Exhibit (PG&E-1), Appendix A) notes possible ways that Load Modifying DR may potentially be better coordinated with the CAISO markets and the CAISO load forecasts. The Commission could encourage the CAISO and other stakeholders to work on these and other possible improvements.

Q 5 In Rulemaking 07-01-041, the Commission included in the scope of the proceeding, the intention to set annual goals for load impacts. How should the Commission determine those goals for Load Modifying Resources? Does the Commission have any guidelines in place that it could use as a starting point for establishing rules to comply with these goals?

A 5 PG&E responds to this question in the testimony of PG&E witness Nicholas K. Ho in Chapter 1 on Demand Response Goals.

Q 6 Decision 12-04-045 discussed the future of DR and questioned what the roles of the utilities and third-party providers would be in administering future programs. Please provide your comments on whether a utility-centric model for load modifying resource DR can meet current and future needs. In addition, please provide your comments on the ability of third-party providers to provide Load Modifying Resource DR to meet current and future needs. As discussed in Decision 12-04-045, should the utilities continue to offer rate-regulated load modifying resource DR if similar services are provided through competitive markets? Should we limit the utilities' role in providing load modifying resource DR? How?

A 6 See the answer to Question 18 in Chapter 4, Supply Resource Issues, for the primary response to this question. The overarching point is that maximizing the amount of cost-effective DR (the DR objective PG&E proposes in Chapter 1) can best be achieved by allowing all stakeholders

(IOUs, Load Serving Entities (LSE), DR providers and customers) to provide both Load Modifying Resource DR and Supply Resource DR. There is no reason to limit IOUs' (or other parties') roles in providing DR, as long as appropriate dual participation rules are in place. Flexibility for all the parties will provide maximum opportunity to capture cost-effective DR.

Third parties can provide Load Modifying Resource DR to the extent they are LSEs or that an LSE hires them to provide it Load Modifying Resource DR. This latter opportunity is illustrated by PG&E's intent to continue to contract with third-party DR providers to provide significant and growing parts of PG&E's DR portfolio.

Utilities should continue to offer Commission-regulated Load Modifying Resource DR, even if Load Modifying DR services are provided through competitive markets. This is consistent with the principle of keeping all reasonable opportunities open to customers, so that the maximum amount of cost-effective DR can be captured. Some customers may prefer utility programs; some may prefer a third-party program. As a LSE, a Utility Distribution Company, and an energy efficiency program provider, utilities have unique opportunities to capture some DR that might otherwise be lost. Also, the Commission has clear and wide-ranging regulatory jurisdiction over the utilities, which enables the Commission to use the utilities to develop and support programs and state policies for demand response. Third parties like the CAISO and non-utility DR providers are not subject to the same Commission's jurisdiction and oversight. Continuing regulated Load Modifying Resource DR through the utilities will serve the Commission's ability to influence future developments.

D. Conclusion

Q 7 Does this conclude your testimony?

A 7 Yes, it does.

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CHAPTER 6

PROGRAM BUDGET APPLI CATION PROCESS

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A. Introduction

Q 1 Please state your name and the purpose of your testimony.

A 1 My name is Nicholas K. Ho and the purpose of my testimony is to respond to Demand Response (DR) program budget application process questions that were included in Attachment A, page 8, to the April 2, 2014 Joint Assigned Commissioner Ruling (ACR) revising scope and schedule for the 2013 Demand Response (DR) rulemaking Phases 2 and 3.[1] My qualifications are included in Exhibit (PG&E-1).

B. Responses to ACR Program Budget Application Process Questions

Q 2 In the Order Instituting Rulemaking, the California Public Utilities Commission (CPUC or Commission) discussed the idea of longer budget cycles. Provide your comments on why the Commission should consider longer budget cycles. Provide justification for the specific length of the budget cycle.

A 2 Implementing a long-term, rolling cycle approach to program planning and implementation will enable the Commission and stakeholders to work toward long-term and comprehensive approaches to growing DR. A long-term DR funding authorization will create market stability, sustain momentum and performance of successful programs, improve the ability to “count” DR for long-term resource planning, and delink contracting from regulatory cycles. Instituting a rolling cycle approach will:

- Create certainty and support robust DR markets to encourage and spur investments.
- Improve effectiveness (e.g., increase savings, lower admin costs related to applications, streamline regulatory processes, promote longer- term contracting).

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1 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings.

- Allow for increased focus on improvements and enhancing DR contracting and programs.
- Enable longer term contracting and program planning to align with greenhouse gas goals, California Independent System Operator Corporation (CAISO) and other regulatory policies and objectives.
- Increase confidence in demand response for procurement planning and CAISO planning.
- Provide for a more unified streamlined DR delivery channel to customers.
- Improve certainty for customer planning.
- Enable opportunity for projects to extend beyond the confines of a short program cycle.

The current method of submitting periodic program applications (with the potential for funding to be denied) creates difficult market conditions for DR providers, often complicates the customer adoption of DR measures, and leads to a lack of recognition of the long term commitment to DR in statewide planning proceedings. To align DR funding with the planning window of the Commission's Long Term Procurement Plan, the CAISO's Transmission Planning Process and the California Energy Commission's Integrated Energy Policy Report, the Commission should adopt a 10-year rolling funding commitment.

Q 3 If the Commission approves longer budget cycles, i.e., 5 or 10 years, should there be regular reviews of the budgets in between the application approval? How often should the reviews occur and what level of scrutiny should be involved and why? How can Evaluation, Measurement and Verification processes be leveraged to improve demand response programs in longer budget cycles?

A 3 Initial funding levels could be initially set at a "base" level to be collected annually. The "base" level of funding would be subject to an automatic annual adjustment mechanism tied to labor escalation and applied only to non-incentive costs. The initial "base" budget values to be set for "year zero" of the rolling portfolio will be based on the program applications filed by the investor-owned utilities (IOU) in November 2015 for the program cycle beginning in 2017. The authorized funding would be projected for the next 10 years (calculated from the "base" authorized funding and including the calculated annual "adjustment") demonstrating a 10-year commitment.

Each year, the approved mechanism would extend the authorized funding one additional year so that there would always be a 10 year forward projection of funding. The authorized funding level (as adjusted by the ongoing "adjustment mechanism") could be modified if needed/triggered in the future by Commission action or an IOU application. Commission action could include modifying specific policy directives or initiating a general review of the authorized funding level for the entire portfolio or a portion of the portfolio. Triggers that could motivate an IOU to file an application (at the discretion of the IOU) for funding changes would include:

- Program cost-effectiveness is forecast to be at risk
- Technical potential or goals are projected to change significantly
- A "game-changing" event occurs

Annual adjustments to rates and updates to associated balancing accounts should follow existing annual ratemaking advice letter processes. The annual advice letters would specify: (1) the next year's authorized funding ("base" authorized funding plus "adjustment"); (2) any unspent funds scheduled to be returned to customers; and (3) the projected subsequent 10 years of authorized funding (calculated from the "base" authorized funding and any "adjustment").

C. Conclusion

Q 4 Does this conclude your testimony?

A 4 Yes, it does.

PACIFIC GAS AND ELEC TRIC COMPANY

CHAPTER 7

BACK-UP GENERATION

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
BACK-UP GENERATION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
BACK-UP GENERATION

A. Summary

- Pacific Gas and Electric Company (PG&E) urges the California Public Utilities Commission (CPUC or Commission) to develop a robust record on the use of fossil-fueled back-up generation (BUG) for demand response before it makes a decision on its future use.
- In Decision 11-10-003, the Commission did not prohibit the use of fossil-fueled emergency back-up generators.
- PG&E does not support a requirement for onsite sub-metering for fossil-fueled BUG participating in Demand Response (DR) programs.

B. Introduction

Q 1 Please state your name and the purpose of your testimony.

A 1 My name is Luke A. Tougas and the purpose of my testimony is to respond to BUG questions that were included in Attachment A to the April 2, 2014 Joint Assigned Commissioner Ruling (ACR) revising scope and schedule for the 2013 Demand Response (DR) Rulemaking Phases 2 and 3.[1] My qualifications are included in Exhibit (PG&E-1).

C. Responses to ACR Back-Up Generation Questions

Q 2 In Decision 11-10-003, Ordering Paragraph (OP) 3, the Commission adopted a policy statement that any demand response program, whether operated by a Commission-regulated Utility or another entity, that uses fossil-fueled emergency BUG for demand reduction should not count towards resource adequacy obligations for any Commission-jurisdictional load shedding entity. Please provide your understanding of the status of the Utilities' compliance with this policy statement.

A 2 In Decision 11-10-003, the Commission did not prohibit the use of fossil-fueled emergency back-up generators; instead, it made a policy

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1 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings.

statement that fossil-fueled BUG should not be used for DR and deferred making an outright prohibition to a future Resource Adequacy (RA) proceeding. In OP 3 of the decision, the Commission ordered the investor-owned utilities (IOU) to work with the Energy Division (ED) to gather more data on the use of BUG for DR. To PG&E's knowledge, no steps have been taken by any of the four entities named in OP 3 to determine what data should be collected, whether such data exists and which entity might possess it. However, in 2010, KEMA completed a study that contained some information on the use of BUG by customers participating in a Critical Peak Pricing (CPP) program and the Base Interruptible Program (BIP). The study is entitled, *California Statewide Process Evaluation of Selected Demand Response Programs - Process Evaluation of PG&E, SCE and SDG&E's Critical Peak Pricing and Base Interruptible Programs.*[2] On pages 2-94 and 2-95, the report discusses the use of BUG by customers participating in the CPP and BIP. I discuss this report further below.

In Decision 11-10-003, the Commission adopted a policy statement that DR enabled by fossil-fueled BUG should not receive RA credit:

> After reviewing parties' comments, we will adopt as a policy statement the Energy Division proposal that any demand response program, whether operated by an IOU or non-IOU, that uses back-up generation for demand reduction should not count towards RA obligations for any Commission-jurisdictional LSEs. This policy is consistent with the Commission's Vision Statement in D.03-06-032 (as well as in prior decisions in the last three-DR budget cycle proceedings). This policy statement applies to the explicit and implicit use of back-up generation for demand response to provide RA capacity. (p. 29)

The Commission then instructed the IOUs to work with ED on implementing the Commission's policy statement, instructed the ED to recommend ways to implement the policy statement, and deferred the details of the process evaluation of the IOUs' 2012-2014 DR applications. The decision states:

> We will require the IOUs work with Energy Division to identify data on how customers intend to use BUGs, and to identify the amount of DR provided by BUGs when enrolling new customers in the DR programs or renewing DR contracts. We will defer the details on the process evaluation to the IOUs' 2012-2014 DR applications. [reference omitted] We will also direct our Energy Division to make recommendations

[2] http://www.calmac.org/publications/Final_DR_Report_4.7.10.pdf.

> regarding ways to implement our policy statement consistent with overall Commission policies." (p. 30)

However, the Commission deferred making a decision prohibiting the use of fossil-fueled BUG for DR to a future RA proceeding, stating:

> At this time, we will not make any change to the RA rules to implement our policy statement regarding RA treatment of back up generation. We recognize parties' concerns regarding lack of data or analysis to the extent that customers use their BUGs for DR and enforcement related issues. Therefore, we will defer the RA rule change to a future RA proceeding when further studies or analysis become available." (D.11-10-003, p. 30)

The only OP in Decision 11-10-003 pertaining to fossil-fueled BUG, OP 3, did not adopt the policy statement made within the body of the decision. OP 3 states:

> In consultation with Energy Division, Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall identify data on how customers intend to use back-up generation and identify the amount of demand response provided by back-up generation when enrolling new customers in, or renewing, demand response programs.

Since Decision 11-10-003 was approved, PG&E has received no guidance from ED on complying with OP 3, including in the guidance decision for the IOUs' 2012-2014 DR applications.

Q 3 How should the Utilities collect data on the customer's use of fossil-fuel emergency BUG during the demand response events? Please identify the amount of demand response provided by BUG on an ongoing basis.

A 3 It is not clear what kind of data the Commission would be seeking, so I proceed based on my interpretation that this question refers to emissions data. First, it should not be the responsibility of the IOUs to collect data on customer's use of fossil-fuel emergency BUG during DR events. These data are collected by the California Air Resources Board (CARB) so any efforts by the IOUs to independently collect these data would seem redundant. Furthermore, because these data are likely under the jurisdiction of the CARB, the IOUs may not have the authority to collect it. Without additional information, I am unaware of how PG&E could, in an efficient and low-cost manner, collect data on customers' use of fossil-fueled BUG during DR events. It might be more practical for the Commission to hire a third-party consultant to perform annual evaluations to determine the extent to which fossil-fueled BUG are used during a DR event.

Before making any decisions on greater regulation of fossil-fueled BUG used for DR, the Commission should consider that because fossil-fueled BUG are subject to emissions limits, there is no evidence to support the contention that prohibiting them from providing DR would reduce the number of hours per year that they are used. For instance, customers with fossil-fueled BUG that provide DR may seek to schedule test events to coincide with occasions when they are called upon to provide DR. In the case of the BIP, because it is called infrequently, an event could possibly be used as an opportunity to test a customer's BUG. If the purpose of a limit or outright prohibition on using fossil-fueled BUG is to reduce emissions, the Commission should first determine that prohibiting them would have a substantive impact on emissions prior to making a decision on this issue.

PG&E does not monitor the amount of DR provided by BUG. However, based on limited data in KEMA's April 7, 2010 California Statewide Process Evaluation of Selected Demand Response Programs – Process Evaluation of PG&E, SCE and SDG&E's Critical Peak Pricing and Base Interruptible Programs, it is likely that many customers participating in DR programs have BUG. According to a survey conducted for KEMA's report, 39 percent of BIP participants surveyed reported having BUG on site (although fuel type was not indicated), 60 percent of which reported using their BUG to respond to a BIP event.[3]

Q 4 How can this policy be further implemented for the Utilities' existing and new demand response programs as Supply Resource and Load Modifying Resources? What methods should the Commission use to exclude demand reduction provided through the use of BUG?

A 4 The Commission should develop a robust record on the use of fossil-fueled BUG for DR before it makes a decision on its future use. This may require the commissioning of an independent study to solicit information from the CARB. Because the information on BUG is largely unknown the Commission should proceed carefully with any effort to limit fossil-fueled BUG from DR participation. Should a significant amount of DR be impacted by such an effort, which based on the KEMA reported discussed above

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3 http://www.calmac.org/publications/Final_DR_Report_4.7.10.pdf, pp. 2-94 – 2-95.

could be the case, the Commission could risk losing a significant amount of DR capacity that is being counted on in the IOUs' RA showings and comprising resource forecasts being used in the Long-Term Procurement Plan proceeding, the California Energy Commission's California Energy Demand Forecast and the California Independent System Operator's Transmission Planning Process.

As I mention above, the Commission should also consider the jurisdictional aspects of prohibiting fossil-fueled BUG providing DR. As PG&E cautioned in its December 13, 2013 *Response of Pacific Gas and Electric Company to Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo*, it is not clear that the Commission has the authority to prohibit the use of fossil-fueled BUG for Supply Resource DR because once the Commission allows retail load to be used for Supply Resource DR, the Supply Resource DR's participation in the CAISO wholesale market would be pursuant to CAISO rules, which are subject to the Federal Energy Regulatory Commission's jurisdiction. (PG&E Comments, p. 17.)[4]

Q 5 Should the Commission require on-site sub-metering for BUG and/or should the Commission require self-certification with the inclusion of data regarding the intended use of BUG during demand response events? If on-site metering is preferred, how should the costs of the metering be recovered?

A 5 No. It is not clear what purpose would be served by requiring sub-metering for BUG, and it is not clear that the additional cost and administrative burden would be worth the benefits. Unless there is a larger policy reason for requiring all behind-the-meter generation to be submetered, applying this requirement only to DR customers would likely create a disincentive to participate proportional to the added cost and administrative burden.

As I cite in the KEMA study, not all DR customers with a BUG actually use that BUG to respond to a DR event. If the Commission decides to limit the

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4 C.f., on January 14, 2014, the United States Environmental Protection Agency revised its National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Internal Combustion Engines pertaining to the use of certain BUG for peak shaving and emergency DR., 40 CFR Part 63, [EPA-HQ-OAR-2008-0708, FRL-9756-4], RIN 2060-AQ58.

use of fossil-fueled BUG for DR, it should utilize an approach that only applies to customers with fossil-fueled BUG and is low cost and not administratively burdensome. Self-certification or self-reporting would meet these two criteria but only if the reason for doing so is clarified by the Commission.

D. Conclusion

Q 6 Does this conclude your testimony?

A 6 Yes, it does.

PACIFIC GAS AND ELEC TRIC COMPANY

CHAPTER 8

COST RECOVERY

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
COST RECOVERY

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
COST RECOVERY

A. Introduction

Q 1 Please state your name and the purpose of your testimony.

A 1 My name is Steven R. Haertle and the purpose of my testimony is to respond to cost recovery-related questions included in Attachment A to the April 2, 2014 Joint Assigned Commissioner Ruling (ACR) revising scope and schedule for the 2013 Demand Response (DR) rulemaking Phases 2 and 3.[1] My qualifications are included in Exhibit (PG&E-1).

B. Responses to ACR Cost Recovery Questions

Q 2 Please provide a summary of Pacific Gas and Electric Company's (PG&E) current DR program cost recovery.

A 2 PG&E currently recovers DR revenue requirements via the Distribution Revenue Adjustment Mechanism (DRAM) and the Energy Resource Recovery Account (ERRA). The DRAM is a two-way revenue balancing account that recovers expenses and costs to administer and evaluate DR programs and to pay customer incentives. Demand response revenue requirements recovered via DRAM are collected from both bundled and Direct Access (DA)/Community Choice Aggregation (CCA) customers through distribution rates. ERRA is a two-way revenue balancing account that recovers Aggregator Managed Portfolio (AMP) program incentives. AMP program incentives recovered via ERRA are collected only from bundled customers via generation rates.

PG&E tracks DR program cycle expenses via the Demand Response Expenditure Balancing Account (DREBA). DREBA tracks actual recorded DR expenses and capital revenue requirements compared to the authorized budget for the majority of programs and activities during the DR program cycle. The DREBA is comprised of two subaccounts:

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1 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings.

- The Operations Subaccount, a one-way balancing account, tracks all recorded operating costs compared to the authorized forecast operating budget over the entire program funding cycle. If actual costs at the end of the program cycle exceed authorized budgets, PG&E's shareholders are at risk for the costs greater than the authorized budgets. If actual costs at the end of the program cycle are less than the authorized budgets, the unspent funding will be returned to customers through the Annual Electric True-Up (AET) advice filing.
- The Incentives Subaccount is a two-way balancing account ensuring recovery of PG&E's actual recorded event-based incentive costs. It records the authorized event-based incentive budget and actual event-based incentive costs incurred. At the end of each year, the under- or over-collection is adjusted, or trued-up the following year and ensures PG&E only recovers its actual event-based incentive costs. These adjustments are then reflected in the budget used to derive the revenue requirement included in the AET advice filing in the following year.

Finally, PG&E has been authorized to record incremental costs associated with integrating its DR programs into the California Independent System Operator energy markets in the Market Redesign and Technology Upgrade Memorandum Account Demand Response Sub Account.

Q 3 Please provide citations for decisions authorizing this recovery for PG&E's DR programs and budgets.

A 3 The following table summarizes DR cost recovery for PG&E DR programs and budgets since 2006:

TABLE 8-1
PACIFIC GAS AND ELECTRIC COMPANY
COMMISSION DECISIONS APPROVING COST RECOVERY MECHANISMS
FOR PG&E DEMAND RESPONSE PROGRAMS (2006-2014)

Line No.	Decision	Authorized	Authorized Revenues ($ millions)	
			Distribution	Generation
1	D.06-03-024	Settlement for 2006-2008 DR programs and budgets	$108.7	
2	D.07-05-029 (p. 15)	AMP program incentives (2007-2012)		$81.0
3	D.08-02-009 (p. 11)	Settlement for 2007-2011 A/C Cycling program	178.8	
4	D.09-08-027 (pp. 218-221)	2009-2011 DR programs and budgets	109.0	
5	D.12-04-045 (pp. 202-204)	2012-2014 DR programs and budgets	191.9	
6	D.13-01-024 (p. 27)	2013-2014 AMP program incentives		36.7
7	Total (2006-2014)		$588.4(a) (83%)	$117.7 (17%)

(a) Total Distribution authorize revenues do not include Base Interruptible Program incentives, which total approximately $20 million annually.

Q 4 Should the current cost recovery policy for DR revenue requirements be changed?

A 4 No. With the exception of AMP incentives, DR revenue requirements are properly recovered via distribution rates (AMP program administration expenses are recovered via distribution rates). As demonstrated in PG&E's rebuttal testimony submitted in Application 11-03-001, it is appropriate to recover DR program revenue requirements via distribution revenue balancing accounts and rates.[2] DR program activities are customer service-related, as they support programs that enable customer to reduce their electricity costs by reducing peak demands. Also, since the inception of DR programs (formerly Load Management) in the early 1980's, DR program administration and management has reported through either the Regulatory Affairs or the Customer Care organization (formerly Customer Operations), which is outside of the PG&E's energy procurement organization. In

2 Exhibit (PG&E-8), A.11-03-001, Pacific Gas and Electric Company, 2012-2014 Demand Response Programs and Budgets, Rebuttal Testimony, pp. 11-1 to 11-5.

addition, and as shown in Table 8-1 above, the California Public Utilities Commission (CPUC or Commission) has consistently authorized recovery of DR revenue requirements through distribution rates.[3]

Q 5 Are there fairness issues that the Commission should consider for Commission-regulated utilities and other Load Serving Entities?

A 5 Yes. Allocating DR revenue requirements between distribution and generation balancing accounts and rates will affect equity between different customer groups. Allocating DR revenue requirements to distribution rates ensures that all customers (bundled, DA, and CCA) will contribute to DR programs that they can participate in and/or benefit from. Allocating DR revenue requirements to generation rates, in contrast, will only impose DR cost recovery on bundled customers, even though DA and CCA customers can participate and/or benefit from DR programs. Furthermore, DR programs are the means for managing load on the grid, which contributes to maintaining its reliability and stability which benefits everyone using the grid.[4]

C. Conclusion

Q 6 Does this conclude your testimony?

A 6 Yes, it does.

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3 *Ibid*, pp. 11-5 to 11-6.

4 *Ibid*, p. 11-3.

PACIFIC GAS AND ELEC TRIC COMPANY

ATTACHMENT A

STATEMENT S OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KENNETH E. ABREU

Q 1 Please state your name and business address.

A 1 My name is Kenneth E. Abreu, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a manager of Demand Response Policy and Planning in the Demand Response Department. I have been in this position for about eight years. I am responsible for planning and policy for demand response, and integration of demand response with major electric market initiatives.

Q 3 Please summarize your educational and professional background.

A 3 I have over 30 years' experience in the electric industry and have held positions in the areas of engineering, program management, contract management, research and development, power plant development, market policy and demand response. I have previously testified before the California Public Utilities Commission and California Energy Commission in a number of proceedings. I am a registered professional engineer with the state of California. I have a master of engineering degree from the University of California at Berkeley in mechanical engineering and a bachelor of science degree from San Jose State University in general engineering.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following chapters in Exhibit (PG&E-1):

- Chapter 4, "Supply Resources."
- Chapter 5, "Load Modifying Resources."
- Appendix D, "Demand Response Cost Effectiveness, Post-Workshop Questions."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEVEN R. HAERTLE

Q 1 Please state your name and business address.

A 1 My name is Steven R. Haertle, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a principal case manager in the Customer Programs and Energy Management Proceedings Department managing regulatory cases related to Demand-Side Management (DSM) programs and electric rate design.

Q 3 Please summarize your educational and professional background.

A 3 I received a bachelor of science degree in agricultural and managerial economics from the University of California, Davis in 1982 and a master of business administration degree from the University of San Francisco in 1994. Since joining PG&E in 1983, I have held a variety of positions with increasing responsibility. I have managed PG&E's time-of-use metering projects and experiments; general rate case marginal costs, revenue allocation, rate design, and DSM showings; development of PG&E electric and gas revenue allocation and rate design; customer information systems conversion; and interval meter data acquisition and load research. I have previously testified before the California Public Utilities Commission on negotiated electric rate reasonableness, electric alternatives for agricultural customers, electric revenue allocation, and DSM program cost recovery. I assumed my current principal case manager position in August 2007.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following chapter in Exhibit (PG&E-1):

- Chapter 8, "Cost Recovery."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF NICHOLAS K. HO

Q 1 Please state your name and business address.

A 1 My name is Nicholas K. Ho, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the director of Demand Response in the Customer Energy Solutions organization. I have been in this position for about two years. I am responsible for the development of PG&E's demand response programs, and integration of demand response with major electric market initiatives.

Q 3 Please summarize your educational and professional background.

A 3 I have a master of engineering degree from the Stanford University in management science and engineering, as well as a bachelor of science degree from Stanford University in computer systems engineering. During my five years at PG&E, I have led a number of strategic initiatives, including the implementation of Home Area Networking technology, analysis of the grid impacts of distributed generation, implementation of PG&E's Customer Data Access initiative, and, most recently, integration of demand response with the wholesale markets. Prior to PG&E, I served as a management consultant with McKinsey & Company, focusing on the retail and consumer goods industries, as well as IT strategy and operations.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following chapters in Exhibit (PG&E-1):

- Chapter 1, "Demand Response Goals."
- Chapter 6, "Program Budget Application Process."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEPHEN J. KUNG

Q 1 Please state your name and business address.

A 1 My name is Stephen J. Kung, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a principal in Demand Response Project Management in the Demand Response Department. I have been in this position for about six months. I am responsible for overseeing the planning and execution of the Demand Response technology initiatives and technology roadmap.

Q 3 Please summarize your educational and professional background.

A 3 I have over 12 years' experience in the electric industry and have held positions in the areas of Information Technology, Energy Procurement, and Interval Metering Support and Demand Response. I have a bachelor of engineering degree from the California Polytechnic University of San Luis Obispo in environmental engineering.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following chapter of Exhibit (PG&E-1):

- Chapter 3, "CAISO Integration Costs."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF LUKE A. TOUGAS

Q 1 Please state your name and business address.

A 1 My name is Luke A. Tougas, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am an expert regulatory policy analyst in the Demand Response Policy and Planning group in the Demand Response Department. I have been in this position for about two-and-a-half years. I am responsible for resource adequacy and long-term planning issues for demand response.

Q 3 Please summarize your educational and professional background.

A 3 I have approximately 13 years of experience in the energy industry with almost eight years of experience in the utility industry. I have held positions in the areas of capacity market policy, demand response, and regulatory relations. I have a master of arts degree from The Johns Hopkins University School of Advanced International Studies in energy, environment, science and technology policy and international economics, and a bachelor of science degree from Saint Michaels College in physics.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following chapters of Exhibit (PG&E-1):

- Chapter 2, "Resource Adequacy Considerations."
- Chapter 7, "Back-Up Generation."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.