Rulemaking: 13-09-001
(U 39 E)
Exhibit No.: PG&E-1, Volume 3
Date: May 22, 2014
Witness(es): Kenneth E. Abreu
Steven R. Haertle
Nicholas K. Ho
Luke A. Tougas

PACIFIC GAS AND ELECTRIC COMPANY

2013 DEMAND RESPONSE RULEMAKING 13-09-011

PHASES 2 AND 3

REBUTTAL TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
2013 DEMAND RESPONSE RULEMAKING 13-09-011
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REBUTTAL TESTIMONY OF NICHOLAS K. HO

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 Opening Testimony of the California Independent System Operator (CAISO) regarding the role of Investor Owned Utilities (IOU) providing Supply Resource Demand Response (DR) into wholesale markets. In addition, I respond to opening testimony regarding proposed DR program goals, specifically testimony from the Joint Demand Response Parties.

B. Response to CAISO Opening Testimony

Q 2 Do you agree with Mr. Goodin that the IOUs should not operate and offer Supply Resource DR, and should only focus on providing Load Modifying Resource DR (p. 11, line 7 to p. 13, line 10)?

A 2 No. IOUs should do both, where it is appropriate.

This section of Mr. Goodin's testimony does not address several fundamental points:

1. **Ratepayers bear the costs and will ultimately pay.** Mr. Goodin seems to imply that by outsourcing the creation and provision of Supply Resource DR and other functions to third parties, ratepayers would no longer be exposed to the associated costs and risks. On the contrary, the costs and risks incurred by these third parties would be reflected in their bids when they respond to IOU Requests for Proposals (RFP) or auctions, which ratepayers will ultimately pay for. Certainly, under the Demand Response Auction Mechanism, the ratepayers would bear the costs and risks associated with winning bidders who would be operating and offering the Supply Resource DR.
2. **A robust third-party market for Supply Resource DR does not yet exist.** On page 13, lines 5-7, Mr. Goodin alleges that third-party DR providers can manage their costs and risks, and do not require ratepayers to fund their infrastructure investments. Mr. Goodin's assertions are not correct. When Pacific Gas and Electric Company

(PG&E) initiated the Intermittent Renewables Management 2 (IRM2) Pilot, PG&E was informed by the third-party DR providers in California that they did not have the infrastructure to bid and dispatch DR into the CAISO market. Instead, PG&E has had to fund the infrastructure to facilitate the bidding and dispatch of DR into the CAISO market for the IRM2 Pilot. As Mr. Gerber noted in his Opening Testimony (Exhibit (PG&E-2), Appendix B), based on his experience administering PG&E's IRM2 Pilot, it will take time for significant amounts of third-party Supply Resource DR to show up. Until then, most Supply Resource DR will go through the IOUs.

3. **PG&E is already working with third party providers to contract for Supply Resource DR.** PG&E is currently working with Olivine to implement the IRM2 Pilot and, in my Opening Testimony (p. 1-8, line 19 to p. 1-10, line 5), I have expressed strong support for issuing more RFPs for third-party DR providers to provide more Load Modifying Resource DR and Supply Resource DR. PG&E's commitment to working with third parties to provide Supply Resource DR is also shown in the Opening Testimony of PG&E witness Mr. Abreu indicating PG&E's intent to convert a subset of the Capacity Bidding Program and Aggregator Managed Portfolio contracts to Supply Resource DR this summer. Both of these programs utilize third-party providers.

C. Response to Joint Demand Response Parties Opening Testimony

Q 3 Do you agree with the position of the Joint Demand Response Parties (p. 9, line 6 to p. 10, line 23) that the California Public Utilities Commission (CPUC or Commission) should establish and "enforce" goals for DR?

A 3 No. Instituting a "hard" DR goal will not necessarily translate into success in meeting that goal. As I discuss in my Opening Testimony (p. 1-12, line 28–p. 1-13, line 13), instituting a "hard" DR goal without a potential study and without a carefully developed plan to meet that potential, presumes that there is sufficient customer willingness to modify their energy use to meet the DR goal. Should there not be enough customer willingness to participate, the incentive payments would likely have to increase to attract the amount and type of customers needed to meet the goal. However, the magnitude of the incentives that can be paid to DR customers is constrained by the DR cost effectiveness protocols. For customers who will not participate for other reasons such as market, business or regulatory risk, those issues must be recognized and addressed as well. Instead, the Commission should identify the major barriers to DR growth and develop a plan to address those that can be remedied while tracking the IOUs' success in growing their respective DR portfolios.

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CHAPTER 2

REBUTTAL TESTIMONY OF KENNETH E. ABREU

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REBUTTAL TESTIMONY OF KENNETH E. ABREU

A. 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 the opening testimony submitted by the California Independent System Operator (CAISO), The Utility Reform Network (TURN), and Southern California Edison Company (SCE).

B. Response to CAISO Opening Testimony

Q 2 Do you agree with the opening testimony of Mr. Millar, page 7, line 15 to page 8, line 7 where Mr. Millar explains, in his view, the importance of demand response (DR) resources being dispatched through the CAISO's economic dispatch system and the alleged shortcomings of dispatching DR via the existing manual notification process?

A 2 No. Mr. Millar's testimony implies that all DR should be Supply Resource DR rather than Load Modifying Resource DR. This section has several incorrect assertions that I will respond to.

First, I note that on page 7, lines 19-22, Mr. Millar mischaracterizes the use of the existing manual notification process when he says, "Reverting to manual notification processes for one resource is counter to the enhancements and improvements made to CAISO system operations thus far and contrary to the concepts of 'smart grid' evolution." First, the manual notification process has been used for many years so no "reverting" would be required, only a continuation of the current procedure. Second, it is not clear what Mr. Millar is referring to when he refers to the "concepts of 'smart grid'" so it is not clear how they apply to how DR programs are dispatched.

The existing manual notification process is actually a CAISO process and is contained in the CAISO Demand Response Resource User Guide, Version 3.0 (Attachment 5) which has been in effect since 2007 and used many times. Page 7 of the document illustrates the process by which the CAISO incorporates day-ahead IOU DR programs scheduled to be dispatched into its Residual Unit Commitment and CAISO Forecast of

CAISO Demand which in turn impact the CAISO's real-time procurement. This manual notification process has been in effect for almost seven years so I would not characterize using the existing manual notification process as "reverting" but rather as the "normal business process." As noted in Pacific Gas and Electric Company (PG&E) Comments of December 13, 2013 in this proceeding (p. 12) and in the Direct Testimony of Dr. Papalexopoulos, there is potential for improvements to the CAISO's manual notification process, but it is nevertheless a process that has functioned well for many years. Also, in his testimony Mr. Millar does not quantify the incremental financial benefits that may be captured for ratepayers by changing all DR to be Supply Resources, nor the cost to ratepayers of this change to bid DR as Supply Resources. Without this information to demonstrate the cost effectiveness of migrating existing DR into Supply Resource DR, it is difficult to justify spending ratepayer funds to do it.

The alleged shortcomings described by Mr. Millar of dispatching DR via these long-standing manual notification processes are incorrect and are not based on facts. First, on page 7, line 25 to page 8, line 2, Mr. Millar claims that the manual notification of DR programs has a shortcoming in that it does not provide "transparency of location." Mr. Millar provides no definition of "transparency of location" or an example to illustrate it. This claim appears to disregard the Daily DR Report that the investor-owned utilities (IOU) provide the CAISO on a weekly basis during the winter months (November-April) and on a daily basis during the summer months (May-October). A copy of the May 14, 2014 report entitled, "PG&E Daily DR Report" is attached as Attachment 1. This report clearly indicates the quantity of DR available to the CAISO on a day-of and day-ahead basis by hour of the day, location and the amount of time needed to dispatch the program. The locational reporting is done by sub-Load Aggregation Point (subLAP); the dispatch time reporting is done by 15-minute, 30-minute, 1-hour or 1-hour + dispatch time. This report also indicates any DR that PG&E has scheduled to dispatch on a day-ahead and day-of basis. This report is sent by e-mail to the CAISO Shift Supervisors as well as the CAISO

Day-Ahead Market operators by 8 a.m.[1] Clearly, the manual notification process of DR programs does provide transparency of location by subLAP, contrary to Mr. Millar's claim.

Second, on page 8, lines 3-4, Mr. Millar claims that the manual notification process compromises the accuracy of DR availability on a day-ahead and real-time basis. Again, he does not define "accuracy of availability" so it is unclear exactly to what he is referring. However, this claim appears to be based on the unsupported assumption that the IOUs would use a more accurate forecasting methodology for DR that is dispatched through the CAISO market than the one used for DR that is dispatched through the manual notification process. However, this is not the case. There is no reason why the forecast accuracy would be better, given the same resources, if the DR was dispatched through the CAISO's economic dispatch system. The same forecasting method would be used for both Load Modifying Resource DR and Supply Resource DR. As I indicated above, the PG&E Daily DR Report (Attachment 1) provides to the CAISO a day-ahead and day-of forecast of PG&E's available DR. Also, as shown in Attachment 2, the accuracy of PG&E's forecasts to the CAISO has been reasonable. PG&E is also working to improve forecasting in the future.

Third, on page 8, lines 5-7, the CAISO claims that the price impacts of DR resources can only properly be represented by being dispatched through the CAISO's economic dispatch system. Mr. Millar provides no evidence to support this claim. However, as demonstrated in their respective Direct and Rebuttal Testimony, Dr. Papalexopoulos and Dr. Zarnikau have shown that Load Modifying Resource DR should impact prices in the CAISO market similar to Supply Resource DR.

In conclusion, the three alleged shortcomings referred to in the testimony of Mr. Millar are not supported by facts.

At this point, it would be useful to reemphasize that PG&E is <u>not</u> taking a position that no DR should be Supply Resource DR. Indeed, PG&E sees a significant role for DR as Supply Resource DR in the future. PG&E is currently bidding some DR as Proxy Demand Resource (PDR), has done so

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1 The May 14 PG&E Daily DR Report was sent at 6:53 a.m.

in the past and plans to do more in the future. PG&E's objection is to forcing all DR (other than dynamic rates) to become Supply Resource DR and that the full-scale transition take place in the near-term while many barriers still exist. This could lead to customers that are uninterested in participating in the CAISO market departing their DR programs and reduce the amount of cost-effective DR simply to meet a requirement that may provide little or no benefit to ratepayers. It will take time for the IOUs, CAISO, DR aggregators, DR providers and customers to gain experience with DR as Supply Resource DR, and to remove barriers that contribute to the cost and complexity. Also, PG&E believes that Load Modifying Resource DR is valuable today and will continue to be in the future, and does not want to lose this value for ratepayers due to the CAISO's desire for DR to be bid into its markets as Supply Resource DR. The CAISO manual notification process ensures that the CAISO has the information it needs for DR, but improvements can be made.

Q 3 On page 8, lines 8-10, Mr. Millar claims that a "manual notification process is completely untenable in today's complex operating environment." Do you agree?

A 3 No. First, as I discussed and demonstrated above in the description of the manual notification process described in Attachments 1 and 5, the CAISO receives the information it needs for transparency of location and accuracy of DR megawatts (MW) dispatched. This process is well-established and works well for existing DR programs. It is incorrect to say they are "completely untenable." Second, as shown in Attachment 3, one can see that it is working from the results of the most recent DR event that the CAISO called on February 6, 2014 when PG&E dispatched its Base Interruptible Program (BIP) at the CAISO's request. PG&E's BIP or its predecessor Interruptible Load Program has been successfully called by the CAISO many times to meet system and local reliability needs since the CAISO's formation. Attachment 4 shows the history of all BIP and Interruptible Load Program dispatches since 1998. If the CAISO truly felt that dispatching DR programs through its manual notification process was "untenable," one would expect that it would not have used it so successfully over so many years. As I point out above, the manual notification process cited by Mr. Millar is in fact the CAISO's process that is based on the CAISO's Demand Response Resource User Guide.

Furthermore, the communication process that is currently used by the CAISO for calling DR for reliability purposes (like the February 6 event) is the same process that is used for conveying operating instructions to PG&E's Grid Control Center for the transmission system. This process consists of daily verbal communication between PG&E grid operators and CAISO operations personnel. The fact that this method is used for transmission system operations establishes that it is not "untenable."

In conclusion, neither the three alleged shortcomings referred to in the testimony of Mr. Millar nor his claim that manual notification is "completely untenable in today's operating environment" are supported by current facts or CAISO operating procedures.

Q 4 Mr. Millar's testimony (p. 8, line 11 to p. 9, line 18) asserts that "ISO is exploring more sophisticated contingency modeling enhancements into its market software, which will put even greater emphasis on the need for all resources to be fully integrated into the market." He implies that this puts a greater need for <u>all</u> DR to be integrated into the CAISO markets. Do you agree?

A 4 No. Forcing <u>all</u> DR to be bid in as Supply Resource DR (with its increased cost and complexity) to support a new CAISO market feature that is in the early stages of development and is of unknown value, is premature and unnecessary. The key problem with Mr. Millar's statement is the phrase "all resources."

If and when these contingency modeling enhancements go into operation they may provide an additional opportunity for Supply Resource DR to capture value, if customers are willing to participate. At that time PG&E and other DR providers can consider if the possible additional financial benefit of providing this new service justifies the additional cost and complexity involved.

Q 5 Mr. Goodin on page 8, line 17 to page 9, line 15, proposes that "emergency and local resource adequacy DR resources" should be Supply Resource DR. Do you agree?

A 5 No. As Mr. Tougas states in his Opening Testimony, Supply Resource DR should receive MW credit to meet the RA requirement and Load Modifying Resource DR should reduce the RA requirement. This principle applies to local RA requirements as well. Emergency DR does not need to be Supply Resource DR to be successful. As I discuss in my Opening Testimony regarding the February 6 BIP event, emergency DR can provide reliability value without being bid and dispatched through the CAISO market.

Mr. Goodin's proposed requirement could lead to a major loss of cost-effective, reliable DR. All of PG&E's dispatchable DR programs (except dynamic rates) currently qualify for local Resource Adequacy (RA) credit and are either emergency or price responsive resources. Mr. Goodin implies they all must become Supply Resources to continue to be valued for local RA.

Regarding emergency DR, I agree with Mr. Goodin that emergency DR must be responsive on short notice to address acute, local CAISO reliability needs. I also agree that the CAISO should have a complete view of what resources, megawatt quantities and operating characteristics are available in real-time. The California Public Utilities Commission (CPUC or Commission) already requires that all DR programs, to be eligible for local RA credit, must be locally dispatchable and as I discuss above, PG&E provides all of this information to the CAISO in a manner consistent with its Demand Response Resource User Guide (see Attachments 1 and 5).

Mr. Goodin also claims that dispatching emergency DR programs through phone calls and e-mail is not an effective way to manage critical resources (p. 9, lines 10-13). However, as I discuss above, this is exactly how the CAISO communicates operating instructions to PG&E's grid operators for the transmission grid. Currently, in order for a transmission system action to be taken, the CAISO places a phone call to the Grid Operations group of a transmission owner. Mr. Goodin's assertion that dispatching an emergency DR program by phone is not efficient places a higher standard on emergency DR to be more accessible than actual transmission infrastructure. It is important to note that emergency DR is rarely called by the CAISO (see Attachment 4) and thus those rare and unique situations may benefit from direct conversations to assure the right actions are taken at the right time.

As noted in Attachment 3 and Attachment 4, emergency DR has been successfully called many times over the years by the CAISO (both locally and systemwide), as Load Modifying Resource DR, not Supply Resource DR. Thus, there is irrefutable evidence that DR as Load Modifying Resource DR can be successfully used for emergency and local RA DR, under the CAISO's current process.

Requiring local RA DR and emergency DR to be Supply Resource DR would be detrimental to meeting the objective of capturing all cost-effective DR. As explained in the Direct Testimony of Mr. Gerber, there are significant amounts of DR that for many reasons may not be able to be Supply Resource DR.

For example, as Mr. Gerber points out in his Direct Testimony at page B-8, one of the barriers to DR being a Supply Resource is that a non-utility Load Service Entity (LSE) may not allow its customer to participate in a PDR or Reliability Demand Response Resource (RDRR). For PG&E, 18 percent of the BIP (PG&E's emergency DR program) customers have a non-PG&E LSE and thus may not be able to be in a RDRR. It would be an undesirable outcome to have to drop these customers from the BIP and lose this reliable DR, simply because they could not be included in a RDRR. This would be a significant loss of cost effective DR.

Another example would be SmartAC™, PG&E's air conditioning cycling program. As Mr. Gerber points out in his Direct Testimony (p. B-10) and in the Olivine Report (PG&E Opening Testimony, Appendix E, Section 4.2.2), SmartAC™ is not a good candidate for PDR due to the large number of customers being incompatible with the CAISO resource registration process. On the other hand, SmartAC is one of the best programs for meeting local RA needs because it is locally dispatchable in less than 10 minutes. In fact, it is already used by PG&E Distribution Operations to drop load at specific substations when needed (a much more targeted use of DR that PG&E needs, but the CAISO does not). But Mr. Goodin's testimony would imply that this highly valuable resource should not be used for local RA, because it is not a Supply Resource. Taking Mr. Goodin's recommendation would lead to a loss of a large amount of cost effective, fast-responding, locally dispatchable DR resources for no sound reason and actually reduce the amount of DR that can provide emergency or local RA.

Thus, the requirement proposed by Mr. Goodin could eliminate a significant amount of DR that could otherwise provide emergency response and local RA value.

Q 6 Has Mr. Goodin properly conveyed how Load Modifying Resource DR should be valued?

A 6 In some parts of his testimony, yes, but in other parts, no. On page 4, line 23 through page 5, line 2, Mr. Goodin correctly indicates that Load Modifying Resource DR can reduce the need for RA capacity. On page 6, line 24 through p. 7, line 4, Mr. Goodin cites the need for Load Modifying Resource DR to be available during the system peak to reduce the RA need. This section correctly notes that it is the "availability" of DR during the peak hours that is the key to DR avoiding the procurement of RA capacity. However, on page 6, lines 19-24, Mr. Goodin seems to be asserting that Load Modifying Resource DR must actually be dispatched during the system peak to reduce the RA need. This is not correct. Load Modifying Resource DR must be available to be dispatched if needed but may or may not actually be dispatched. This misunderstanding also shows up on page 6, lines 3-7 and page 8, lines 14-16. However, the shortcoming with Mr. Goodin's position is that if the DR is not needed for dispatch, then it will not be seen in the load and not receive RA value. Instead, it should still be valued for RA, just as a generator would, if it were available to be called but was not called because it was not needed.[2] The only difference would be that the Load Modifying Resource DR would reduce the RA requirement. In years with economic downturns or cool summers, there may be many RA valued resources (both DR and generation) that are not operated because they are not needed. But the "insurance" value is still there and should be fully valued. Otherwise, Mr. Goodin's suggestion would lead to

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2 Load Modifying Resource DR does not need a CAISO Must Offer Obligation like generation does because it is already required by the CPUC RA rules and program design to be available for dispatch by the CAISO.

additional costs to ratepayers, as they would need to pay for redundant RA that is already provided by Load Modifying Resource DR. See the Rebuttal Testimony of Dr. Zarnikau for a more extensive discussion of this point.

Q 7 Do you agree with Mr. Goodin's proposal that all Load Modifying Resource DR programs should be subject to the same performance obligations and non-compliance penalties as the IOUs' Aggregator Managed Portfolio (AMP) contracts (p. 10, lines 25-28)?

A 7 No. The non-compliance penalties for each of PG&E's DR programs reflect the unique nature of each DR program, and effectively balance the associated risks and benefits. For example, programs with more generous payment structures may also contain stronger penalty structures. Conversely, AMP-type penalties make no sense where the incentive provided is smaller, or does not involved capacity payments such as found in the AMP contracts. Forcing one particular penalty structure for DR will unnecessarily limit the amount of cost-effective DR that can be captured. Mr. Goodin provides no facts to support his contention that aligning the non-compliance charges of all of the IOUs' Load Modifying Resource DR programs with those of the AMP contracts will provide any benefits.

C. Southern California Edison Company Issues

Q 8 SCE shows most of their DR programs as Supply Resource DR while PG&E shows none. Why is this?

A 8 PG&E and SCE each base their proposed categorization on a different set of criteria for qualifying as Supply Resource DR. As I stated in my opening testimony, a DR program should be Supply Resource DR if (1) it provides a product that the CAISO directly procures (e.g., ancillary services); <u>or</u> (2) the incremental benefits of bidding DR as Supply Resource DR exceed the associated incremental costs. SCE's criteria for a DR program to qualify as Supply Resource DR is (1) it must be capable of being dispatched within the CAISO's market rules; and (2) the DR program's incentive must be below the CAISO's maximum price for energy bids.

San Diego Gas & Electric Company (SDG&E) also points to the Capacity Bidding Program and BIP as potential Supply Resource DR.

Under these two sets of proposed criteria, PG&E finds that none of its DR programs currently qualify as Supply Resource DR but SCE finds that many of its DR programs currently qualify as Supply Resource DR.

However, all three IOUs indicate that much more experience is needed to determine how much DR can actually be bid as Supply Resource DR and that efforts need to be made to reduce the complexity and cost of bidding as Supply Resource DR before full scale bidding may be feasible (see SCE p. 19, line 18 to p. 20, line 21; see SDG&E Chapter IV, p. GK-2, lines 8-15). Thus, this difference in labeling programs does not imply that the programs that might be able to become Supply Resource DR after barriers are removed should be bid as Supply Resource DR now.

It is also important to note that just because a program is not categorized as Supply Resource DR, does not mean that part of the program cannot be bid in as a Supply Resource DR. PG&E has done this in the past and plans to do so in the future.

D. The Utility Reform Network Issues

Q 9 On page 15, lines 3-21, Mr. Hawiger recommends that all existing DR programs be terminated over the period 2016-2018. Do you agree with his recommendation?

A 9 No. TURN's recommendation is based on several points of faith, not on fact. Adopting TURN's recommendation creates a very real risk of needlessly losing a large amount of cost effective DR. For TURN's recommendation to work, two things would have to be true: (1) all of the customers participating in existing DR programs would be willing to participate in DR resources procured through the Demand Response Auction Mechanism (DRAM); and (2) the DRAM design and implementation would be successful. TURN provides no factual evidence that either would be the case.

TURN's recommendation to eliminate existing DR programs to avoid taking DR customers away from the DRAM ignores the fundamental fact that DR relies on customer willingness to participate. Under the current DRAM proposal, any DR procured through the DRAM would be Supply Resource DR which means it would be required to bid into the CAISO market consistent with the CAISO's must-offer obligation (MOO) which is currently under development. TURN has provided no evidence to indicate whether the existing customers participating in DR programs would be willing or able to participate in the CAISO market.[3] Even if TURN was able to provide this information, it could only be based on an expectation of what the CAISO's MOO will be for wholesale DR. Eliminating existing DR programs based on the expectation that all DR participants will shift over to Supply Resource DR procured through the DRAM risks losing all of those customers who cannot or will not do so. Also, the Direct Testimony of Mr. Gerber (Exhibit (PG&E-1), Appendix B) shows that a major portion of the DR portfolio would be lost, if all were required to be Supply Resource DR (the product that would be procured through the DRAM).

TURN's recommendation is also flawed because it assumes that the DRAM design will be successful. Given that the DRAM has not been finalized or approved by the Commission, TURN has not explained why it is worth the risk of eliminating significant amounts of DR resources for a DR auction mechanism about which many parties to this proceeding have expressed serious concerns. Moreover Mr. Hawiger (Opening Testimony, p. 16, line 3-13), Mr. Woodruff (Opening Testimony, *passim),* as well as the Opening Testimony of many other parties (PG&E, SCE, California Large Energy Consumers Association, SDG&E, Joint Parties and Sierra Club), clearly indicate that they do not see the proposed DRAM design as being ready for full implementation.

TURN's recommendation to eliminate existing DR programs is not supported by any facts or reasonable assumptions. The recommendation would risk losing significant amounts of DR.

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3 See Opening Testimony of Joint DR Parties B9 to B12, pages 25-28 where aggregators express concern about the MOO and DR.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT 1

PG&E DAILY DEMAND RESPONSE REPORT – MAY 14, 2014

IOU:	Pacific Gas & Electric
Date/Time Published:	Wednesday, May 14, 2014

PG&E: Today

Operating Day: Wednesday, May 14, 2014

IOU Scheduled Day-of DR (MWs)

Hour Ending:	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Central Coast PGCC	-	-	-	-	1.0	1.0	1.1	3.5	2.7	2.7	2.7	-	-	-	-	-
East Bay (Bay Area) PGEB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fresno PGF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geysers PGFG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Humboldt PGHB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Los Padres PGLP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Bay PGNB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Coast PGNC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Valley PGNV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peninsula (Bay Area) PGP2	-	-	-	-	-	-	-	0.7	0.7	0.7	0.7	-	-	-	-	-
Sacramento Valley PGSA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Bay (Bay Area) PGSB	-	-	-	-	4.2	4.6	4.6	7.2	7.7	7.6	7.6	4.1	-	-	-	-
San Francisco (Bay Area) PGSF	-	-	-	-	0.4	0.5	0.5	2.9	2.7	2.7	2.7	0.1	-	-	-	-
Sierra PGSI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Joaquin PGSN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stockton PGST	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SYSTEM-WIDE Dispatch Only	-	-	-	-	-	-	30.3	40.3	47.2	51.0	51.6	-	-	-	-	-
Total Scheduled DR MWs for Today:	**-**	**-**	**-**	**-**	**5.6**	**6.0**	**36.4**	**54.7**	**61.0**	**64.7**	**65.3**	**4.2**	**-**	**-**	**-**	**-**

Forecast of Available DR Day-of (MWs)

Hour Ending:	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Central Coast PGCC																
15-minute	-	0.1	0.1	0.1	0.2	0.3	0.4	0.4	0.5	0.4	0.4	0.4	0.3	0.2	0.2	0.1
30-minute																
1-hour	6.2	6.1	6.0	5.0	5.6	5.6	5.4	4.8	4.1	3.9	3.8	4.3	5.9	7.0	7.2	7.0
> 1-hour	-	-	-	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	-	-	-	-	-
Sum Total:	6.2	6.2	6.1	6.4	7.1	7.2	7.1	6.5	5.9	5.5	5.5	4.6	6.2	7.2	7.4	7.2
East Bay (Bay Area) PGEB																
15-minute	-	3.0	4.7	7.2	10.1	14.4	18.4	22.4	24.1	18.4	18.6	19.6	15.9	12.8	9.4	6.5
30-minute																
1-hour	40.9	41.5	41.0	39.0	37.3	36.6	35.9	34.0	32.8	32.6	32.5	33.0	33.1	32.6	32.0	31.8
> 1-hour	-	-	-	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	-	-	-	-	-
Sum Total:	40.9	44.5	45.8	49.2	50.4	53.9	57.2	59.3	59.9	53.9	54.1	52.6	49.0	45.4	41.4	38.3

IOU:	Pacific Gas & Electric
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Fresno PGF1																
15-minute	-	2.3	3.7	5.6	7.9	11.3	14.6	17.7	18.8	14.7	14.8	15.5	12.5	10.2	7.4	5.1
30-minute																
1-hour	11.6	12.6	12.2	12.2	12.0	11.9	11.0	9.8	10.1	9.5	9.5	9.5	9.8	10.3	9.5	9.3
> 1-hour	-	-	-	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	-	-	-	-	-
Sum Total:	11.6	14.9	15.9	44.0	45.9	49.3	51.6	53.5	55.0	50.3	50.4	25.0	22.3	20.5	17.0	14.4
Geysers PGFG																
15-minute	-	0.3	0.6	0.8	1.2	1.7	1.9	2.4	2.8	1.8	1.9	2.1	1.7	1.4	1.0	0.7
30-minute																
1-hour	2.2	2.0	1.9	2.1	2.2	2.0	1.8	1.6	1.3	1.2	1.2	1.4	1.4	1.5	1.5	1.4
> 1-hour	-	-	-	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-	-	-	-	-
Sum Total:	2.2	2.3	2.5	3.4	3.8	4.1	4.2	4.5	4.5	3.5	3.5	3.5	3.2	2.9	2.5	2.1
Humboldt PGHB																
15-minute	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30-minute																
1-hour	5.5	5.6	4.6	5.4	5.1	5.0	5.1	4.1	3.5	3.5	3.8	3.9	3.9	3.9	4.0	3.9
> 1-hour	-	-	-	1.1	1.1	1.1	1.1	0.6	0.6	0.6	0.6	-	-	-	-	-
Sum Total:	5.5	5.6	4.6	6.5	6.2	6.1	6.2	4.8	4.1	4.1	4.4	3.9	3.9	3.9	4.0	3.9
Los Padres PGLP																
15-minute	-	0.9	1.4	2.2	3.0	4.3	5.1	6.2	6.6	4.9	4.9	5.8	4.7	3.8	2.8	1.9
30-minute																
1-hour	39.8	39.8	40.4	40.2	39.8	39.9	39.5	38.6	38.5	39.1	39.6	40.3	40.9	40.8	40.7	40.1
> 1-hour	-	-	-	44.7	44.7	44.7	44.7	44.7	44.7	44.7	44.7	-	-	-	-	-
Sum Total:	39.8	40.7	41.9	87.1	87.5	88.9	89.3	89.5	89.9	88.7	89.3	46.1	45.6	44.7	43.5	42.0
North Bay PGNB																
15-minute	-	0.3	0.4	0.6	0.9	1.3	1.4	1.8	2.1	1.4	1.4	1.6	1.3	1.0	0.8	0.5
30-minute																
1-hour	3.0	3.2	3.5	3.3	2.6	3.0	3.1	2.6	2.5	2.5	2.8	2.9	2.9	2.9	2.9	2.8
> 1-hour	-	-	-	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	-	-	-	-	-
Sum Total:	3.0	3.5	3.9	4.7	4.2	5.1	5.3	5.2	5.3	4.6	5.0	4.5	4.2	3.9	3.6	3.3

IOU:	**Pacific Gas & Electric**															
Date/Time Published:	**Wednesday, May 14, 2014**															
North Coast PGNC																
15-minute	-	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.2	0.1
30-minute																
1-hour	4.2	4.3	3.2	4.3	4.2	4.1	3.6	1.7	1.3	1.2	1.0	0.9	0.9	0.9	0.8	0.5
> 1-hour	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-
Sum Total:	4.2	4.4	3.3	4.4	4.4	4.4	3.9	2.1	1.8	1.5	1.2	1.2	1.2	1.1	0.9	0.6
North Valley PGNV																
15-minute	-	0.4	0.6	1.0	1.3	1.9	2.4	3.0	3.2	2.4	2.4	2.6	2.1	1.7	1.2	0.9
30-minute																
1-hour	28.1	28.4	27.6	28.5	28.7	28.4	27.5	25.9	27.3	27.4	27.0	27.0	25.9	27.4	28.0	27.4
> 1-hour	-	-	-	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	-	-	-	-	-
Sum Total:	28.1	28.8	28.2	29.9	30.4	30.7	30.3	29.3	30.9	30.2	29.9	29.5	28.0	29.1	29.2	28.3
Peninsula (Bay Area) PGP2																
15-minute	-	0.5	0.8	1.2	1.7	2.5	3.0	3.6	3.9	2.9	2.9	3.4	2.7	2.2	1.6	1.1
30-minute																
1-hour	18.6	17.6	17.2	19.1	19.2	19.5	19.5	19.0	18.9	18.4	18.3	18.7	17.6	17.7	17.9	18.1
> 1-hour	-	-	-	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	-	-	-	-	-
Sum Total:	18.6	18.1	18.0	22.5	23.1	24.2	24.7	24.8	24.9	23.4	23.5	22.0	20.3	19.9	19.5	19.2
Sacramento Valley PGSA																
15-minute	-	1.6	2.5	3.8	5.3	7.6	9.4	11.6	12.7	9.3	9.4	10.0	8.1	6.5	4.8	3.3
30-minute																
1-hour	25.7	26.3	26.6	26.1	25.3	25.6	24.3	23.5	22.3	21.9	23.1	23.6	23.8	23.6	23.2	22.5
> 1-hour	-	-	-	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	-	-	-	-	-
Sum Total:	25.7	27.8	29.1	31.5	32.3	34.9	35.4	36.7	36.7	32.9	34.2	33.6	31.9	30.2	28.0	25.8
South Bay (Bay Area) PGSB																
15-minute	-	0.9	1.5	2.3	3.2	4.6	5.5	6.6	7.0	5.2	5.2	6.2	5.1	4.1	3.0	2.1
30-minute																
1-hour	25.2	25.7	26.0	26.2	23.0	22.8	22.5	22.0	21.7	21.2	20.7	20.3	23.2	22.7	22.5	22.2
> 1-hour	-	-	-	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	-	-	-	-	-
Sum Total:	25.2	26.6	27.5	34.3	32.1	33.2	33.7	34.3	34.5	32.2	31.7	26.6	28.3	26.8	25.5	24.3
San Francisco (Bay Area) PGSF																
15-minute	-	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
30-minute																
1-hour	0.4	0.4	0.4	0.4	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5
> 1-hour	-	-	-	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	-	-	-	-	-
Sum Total:	0.4	0.4	0.4	2.0	1.9	1.9	1.9	2.0	2.1	2.1	2.1	0.5	0.5	0.5	0.5	0.5

IOU:	**Pacific Gas & Electric**															
Date/Time Published:	**Wednesday, May 14, 2014**															
Sierra PGSI																
15-minute	-	0.6	1.0	1.5	2.1	2.9	3.4	4.3	4.9	3.3	3.3	3.7	3.0	2.4	1.8	1.2
30-minute																
1-hour	2.2	2.1	2.1	2.1	2.1	2.1	2.0	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8
> 1-hour	-	-	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-	-	-	-	-
Sum Total:	2.2	2.7	3.1	3.8	4.4	5.2	5.6	6.4	7.0	5.3	5.3	5.5	4.8	4.2	3.6	3.0
San Joaquin PGSN																
15-minute	-	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0
30-minute																
1-hour	0.7	0.7	0.7	0.7	0.6	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
> 1-hour	-	-	-	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	-	-	-	-	-
Sum Total:	0.7	0.7	0.7	1.0	0.9	0.8	0.8	0.7	0.7	0.7	0.7	0.4	0.4	0.3	0.3	0.3
Stockton PGST																
15-minute	-	1.4	2.2	3.4	4.8	6.8	7.4	8.9	9.4	6.5	6.6	9.3	7.5	6.1	4.4	3.1
30-minute																
1-hour	26.3	25.7	25.7	25.6	24.4	22.3	19.4	18.2	18.6	18.1	18.6	18.8	18.4	19.0	18.7	18.4
> 1-hour	-	-	-	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	-	-	-	-	-
Sum Total:	26.3	27.1	27.9	31.1	31.2	31.2	28.9	29.2	30.0	26.7	27.3	28.1	25.9	25.0	23.1	21.5
System-wide Dispatch Only																
15-minute																
30-minute																
1-hour																
> 1-hour	-	-	-	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	-	-	-	-	-
Sum Total:	-	-	-	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	-	-	-	-	-
Total Available DR All Areas:	**240.7**	**254.4**	**258.9**	**390.5**	**394.6**	**409.9**	**414.8**	**417.8**	**421.9**	**394.3**	**396.8**	**287.6**	**275.6**	**265.8**	**250.0**	**234.8**

IOU:	Pacific Gas & Electric
Date/Time Published:	Wednesday, May 14, 2014

PG&E: Tomorrow

Operating Day - Thursday, May 15, 2014

IOU Scheduled Day-Ahead DR (MWs)

Hour Ending:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Central Coast PGCC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
East Bay (Bay Area) PGEB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fresno PGF1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Geysers PGFG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Humboldt PGHB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Los Padres PGLP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Bay PGNB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Coast PGNC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
North Valley PGNV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peninsula (Bay Area) PGP2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sacramento Valley PGSA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
South Bay (Bay Area) PGSB	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Francisco (Bay Area) PGSF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Sierra PGSI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
San Joaquin PGSN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stockton PGST	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
System-wide Dispatch Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Scheduled DR MWs for Tomorrow:	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

IOU:	Pacific Gas & Electric
Date/Time Published:	Wednesday, May 14, 2014

Forecast of Available DR Day-of + Day-Ahead (MWs)

Hour Ending:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Central Coast PGCC	7.1	6.6	6.7	6.4	6.2	6.4	7.2	6.5	6.2	6.2	6.1	9.1	9.8	9.9	9.8	9.3	8.5	8.2	8.1	4.6	6.2	7.2	7.4	7.1
East Bay (Bay Area) PGEB	31.6	31.5	31.4	32.5	37.5	39.4	40.6	42.0	40.9	44.2	45.3	54.7	47.2	50.3	52.8	54.5	55.3	49.2	49.7	41.7	47.0	43.9	40.3	37.5
Fresno PGF1	7.6	7.3	6.8	6.8	6.8	7.9	9.8	11.1	11.6	15.0	16.0	62.2	63.1	66.5	69.5	71.4	72.6	68.3	68.7	24.7	23.0	21.1	17.4	14.7
Geysers PGFG	1.4	1.2	1.2	1.3	1.2	1.4	1.8	2.0	2.2	2.2	2.4	4.7	7.1	7.3	7.2	7.3	7.3	6.4	6.5	5.0	2.7	2.6	2.2	1.9
Humboldt PGHB	3.6	3.4	3.3	3.2	3.6	4.6	5.6	5.5	5.5	5.6	4.6	7.0	6.7	6.5	6.6	5.2	4.5	4.6	4.8	3.9	3.9	3.9	4.0	3.9
Los Padres PGLP	37.7	36.7	35.5	35.3	36.4	37.7	39.1	40.0	39.8	40.7	41.9	97.7	98.1	99.5	100.3	100.5	100.6	99.8	100.5	46.5	45.9	44.9	43.7	42.1
North Bay PGNB	2.4	2.3	2.3	2.2	2.1	2.1	2.1	2.7	3.0	3.5	3.8	4.9	4.5	5.2	5.3	5.2	5.3	4.6	5.0	4.2	3.9	3.7	3.4	3.2
North Coast PGNC	0.4	0.4	0.4	0.4	0.8	2.0	4.3	4.2	4.2	4.4	3.3	5.0	5.0	4.9	4.5	2.7	2.3	2.0	1.8	1.2	1.1	1.1	0.9	0.6
North Valley PGNV	26.0	23.7	23.7	24.3	24.3	26.0	28.5	28.3	28.1	28.9	28.3	31.7	32.2	32.6	32.2	31.2	32.8	32.1	31.9	29.7	28.2	29.2	29.3	28.4
Peninsula (Bay Area) PGP2	18.2	18.0	17.4	16.9	16.4	15.5	16.3	18.1	18.6	18.0	17.9	23.0	23.6	24.5	24.8	24.8	25.0	23.5	23.6	21.4	19.7	19.4	19.1	19.0
Sacramento Valley PGSA	21.3	20.7	20.5	20.4	20.7	22.4	24.4	25.2	25.7	27.9	29.2	45.7	46.5	49.2	50.1	51.5	51.5	47.7	49.2	34.2	32.4	30.6	28.3	26.0
South Bay (Bay Area) PGSB	21.7	21.7	21.5	21.4	21.5	22.4	23.5	24.5	25.2	26.5	27.3	37.4	38.8	40.1	40.2	40.4	40.6	38.2	37.9	29.2	27.4	26.1	25.0	23.9
San Francisco (Bay Area) PGSF	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	4.6	4.9	4.9	4.9	5.0	5.0	4.9	4.9	0.7	0.4	0.5	0.5	0.5
Sierra PGSI	2.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.9	3.3	4.3	5.1	6.2	7.0	8.1	8.6	6.9	7.0	6.7	5.8	5.0	4.1	3.4
San Joaquin PGSN	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.7	0.7	0.7	0.7	1.1	0.9	0.9	0.8	0.7	0.7	0.7	0.7	0.4	0.4	0.3	0.3	0.3
Stockton PGST	16.0	15.9	16.1	17.2	20.2	22.8	24.7	25.8	26.3	27.2	28.0	39.2	39.4	39.4	37.4	37.8	38.5	35.3	36.3	28.4	26.2	25.3	23.3	21.6
System-wide Dispatch Only	-	-	-	-	-	-	-	-	-	-	-	28.8	42.5	42.5	106.3	116.2	119.8	119.7	85.8	13.6	-	-	-	-
Total Available DR All Areas:	**197.7**	**192.3**	**189.6**	**191.1**	**200.6**	**213.5**	**231.1**	**239.3**	**240.7**	**254.2**	**258.4**	**461.1**	**475.3**	**490.5**	**559.9**	**571.7**	**579.1**	**552.2**	**522.6**	**296.0**	**274.2**	**264.6**	**249.2**	**234.2**

Note: The 'Lead Time' listed is customer notification lead time.

PG&E Demand Response Program Forecast

Demand Response Program Forecast for CAISO
Date Reported: Wednesday, May 14, 2014
Demand Response Provider: Pacific Gas & Electric

Monthly Nominated Programs - Aggregator Manged Portfolio and Capacity Bidding Program (CBP)

Program	Program Type	Event Limits Hour per Mo/Yr	Lead Time	Earliest Start Time	Latest End Time	Maximum Event Duration	Event Pending / Completed (Hours)	Hours Remaining	Total MW Available Per Hour
Aggregator Managed Portfolio - Locational Dispatch	Day Of	May - Oct 80 hrs/yr	30-90 mins	11:00 AM	7:00 PM	6 hrs	0	80	xxx
Aggregator Managed Portfolio - System-wide	Day Of	May - Oct 80 hrs/yr	30-90 mins	11:00 AM	7:00 PM	6 hrs	0	80	xxx
Aggregator Managed Portfolio - Locational Dispatch	Day Ahead	May - Oct 80 hrs/yr	3PM Day Ahead	11:00 AM	7:00 PM	6 hrs	0	80	xxx
Capacity Bidding Program DA 1-4	Day Ahead	30 hrs/mo	3PM Day Ahead	11:00 AM	7:00 PM	4 hrs	0	30	6.8
Capacity Bidding Program DO 1-4	Day Of	30 hrs/mo	3 hours	11:00 AM	7:00 PM	4 hrs	0	30	8.2
Capacity Bidding Program DO 2-6	Day Of	30 hrs/mo	3 hours	11:00 AM	7:00 PM	6 hrs	0	30	5.6

Demand Bidding Program (DBP), Peak Day Pricing (PDP), and SmartRate

Program	Program Type	Event Limits Per Year	Lead Time	Set Start Time	Set End Time	Set Event Duration	Events Pending/ Completed (Events)	Events Remaining	Total MW Available Per Hour
DBP	Day Ahead	Unlimited	Noon Day Ahead	12:00	20:00	8 hrs	0	Unlimited	6.1
PDP	Day Ahead	15 events/yr	2PM Day Ahead	12:00	18:00	6 hrs	0	15	33.7
SmartRate	Day Ahead	15 events/yr	3PM Day Ahead	14:00	19:00	5 hrs	0	15	40.2

Emergency Programs

Program	Program Type	Event Limits Hour per Mo/Yr	Lead Time	Earliest Start Time	Latest End Time	Maximum Event Duration	Season Completed (Hours)	Hours Remaining	Total MW Available Per Hour
Base Interruptible Program	Day Of	1/day 10/mo 180 hrs/yr	30 mins	Midnight	Midnight	4 hrs	4	176	223.0
SmartAC	Day Of	100 hrs/yr		Midnight	Midnight	6 hrs	0	100	90.9

xxx - For purposes of testimony in R.13-09-011, PG&E has redacted aggregator information that the aggregators would consider commerically sensitive.

Instructions for Sheet "MW Available by Response Time"	
Field	**Description**
[IOU Name]: Day-of	In this category, report forecasted MWs both scheduled and available for the current day (Day-of).
IOU Scheduled Day-of DR MWs	Provide the MW amount the IOU is scheduling/committing by hour for the current day. The MW amount should include IOU committed DR as well as any DR that was committed from the following day per CAISO request.
Hour Ending	Align all DR MW forecasts with ISO hour-ending scheduling convention, e.g. HE 9 is from 8 AM to 9 AM.
Total Scheduled DR MWs for Today	The aggregate total of all DR program megawatts scheduled/committed by the IOU for the current day.
Forecast of Available DR Day-of (MWs)	Provide the incremental DR MW amount that remains available by hour and by response time (and areas, where applicable) that was not already committed by the IOU that remains available to the ISO in the current day.
Response Time	Provide the aggregate MW amount available by response time. Response time is the time it takes from ISO notification to full load curtailment.

[IOU Name]: Day-ahead	In this category, report forecasted MWs scheduled and available for the following day (Day-ahead).
IOU Scheduled Day-Ahead DR MWs	The aggregate MW amount of DR the IOU is scheduling/committing by hour for the following day, i.e. the day-ahead.
Total Scheduled DR MWs for Tomorrow	The aggregate MW amount of DR the IOU is scheduling/committing by hour for the following day, i.e. the day-ahead.
Forecast of Available DR Day-ahead	These are incremental MWs available day-ahead that are not already committed and could be made available to the CAISO upon request.
[Area specific Day-ahead MWs listed in these fields]	Provide the forecast of incrementatl MWs available that have not already been committed by the IOU in each area or areas.

Instructions for Sheet "MW Available by Program"	
Field	**Description**
Event Date	Event date is the date that the actual event shall take place, not the date that the report is provided to the CAISO
Program	All Day Ahead Programs in the portfolio will be reflected in the report. This will allow the CAISO to view programs that are being called as well as those that are not being called.
Program Type	The program type is either Day Ahead or Day Of
# of Accounts	The # of accounts represents the total number of service accounts (not individual customers) that are forecasted to participate in the event (not the accounts enrolled in the program).
Trigger	The trigger defines the reason why the program is being called
Date/Time Published	Identifies the date and time when the report is provided to the CAISO. This field will be used to determine when multiple reports are provided on the same date at different times.
HE#	The HE# reflects that Hour Ending in Pacific Daylight Time. For example, HE 12 reflect usage from 11:00 AM to 11:59 AM PDT.
Estimated Reduction	Estimated Reduction shall be provided in MW's and rounded to 1 decimal.
Aggregator Managed Portfolio	Aggregator Managed Portfolio forecast is calculated as the aggregate of the monthly forecasts provided by each aggregator.
Base Interruptible Program	Base Interruptible Program forecast is calculated as the average hourly load of a number of previous similar days, less the firm service level.
Capacity Bidding Program Day Ahead	Capacity Bidding Program forecast is calculated as the current month's nominations by product.
Demand Bidding Program	Demand Bidding Program forecast is calculated as the YTD average load reduction for each event hour.
Peak Day Pricing	Peak Day Pricing forecast is calculated as a monthly load impact with enrollment count, day of the week, and hourly weather taken into account.
SmartAC	SmartAC forecast is calculated as a monthly load impact with enrollment count, day of the week, and hourly weather taken into account, by sublap.
SmartRate	SmartRate forecast is calculated as a monthly load impact with enrollment count, day of the week, and hourly weather taken into account.

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CHAPTER 2

ATTACHMENT 2

PG&E 2012 AND 2013 F ORECASTING VS. ACTUA LS

2013 Daily Forecasted vs. Actual DR

Programs	No. of DR Events	Daily Forecast	Ex-Post
		(Averaged MW over All Events)	
AMP-DA	7	56	40
AMP-DO	6	117	107
BIP	2	122	112
CBP-DA	5	7	4
CBP-DO	5	10	9
DBP	6	20	19
PDP	8	41	40
SmartAC	2	8	5
SmartRate	8	41	44

Overall performance and forecasting was good

The data incorporates re-tests for low or non-performers (thus, lowering the final number since it's averaged, and making the forecasting % a wider range)

Due to local calls, the MW may appear smaller than the MW attributed to the entire program

2012 Daily Forecasted vs. Actual DR

Programs	No. of DR Events	Daily Forecast (Averaged MW over All Events)	Ex-Post (Averaged MW over All Events)
AMP-DA	3	44	50
AMP-DO	3	138	129
BIP	1	219	221
CBP-DA	5	26	20
CBP-DO	6	28	23
DBP	3	38	38
PDP	7	28	25
SmartAC	1	110	78
SmartRate	6	19	19

Overall performance and forecasting was good

The data incorporates re-tests for low or non-performers (thus, lowering the final number since it's averaged, and making the forecasting % a wider range)

Due to local calls, the MW may appear smaller than the MW attributed to the entire program

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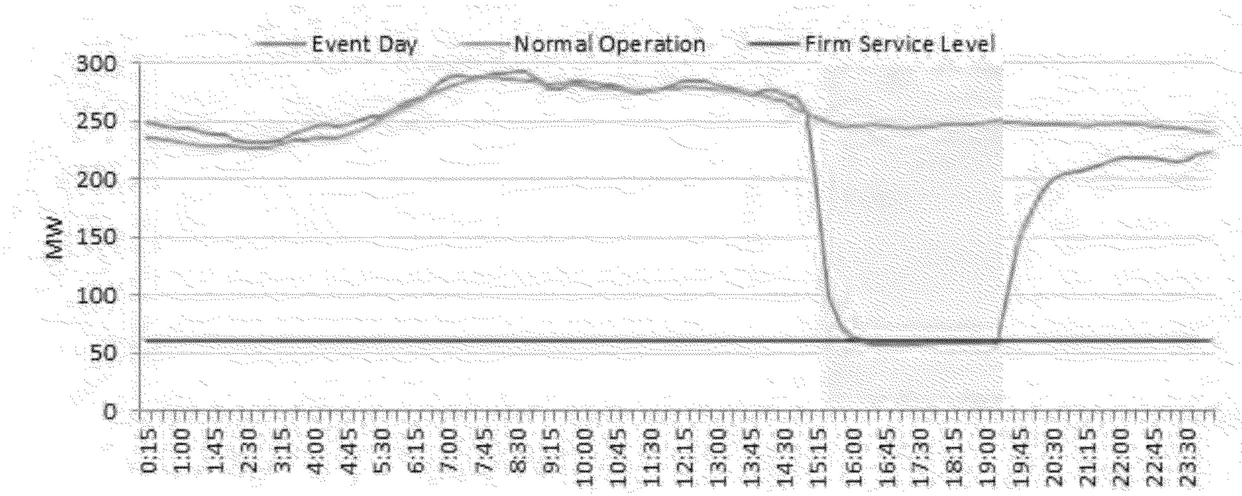
ATTACHMENT 3

PG&E BASE INTERRUPTIBLE PROGRAM – FEBRUARY 6, 2014

ATTACHMENT 3

PG&E Base Interruptible Program

February 6, 2014 - 3:15 p.m. to 7:15 p.m.



	Average
Reduction	184 MW
Forecast	168 MW
Reduction/Forecast	109%

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ATTACHMENT 4

PG&E INTERRUPTIBLE EVENT HISTORY – 1998-2014

Non Firm and Base Interruptible Program Events						
Date	**Year**	**Program Activated**	**Event Start Time**	**Event End Time**	**Event Duration**	**Notes**
July 27, 1998	1998	Non Firm	1600	1700	1	
August 4, 1998	1998	Non Firm	1300	1900	6	
August 31, 1998	1998	Non Firm	1600	1715	1.15	
September 1, 1998	1998	Non Firm	1300	1645	3.45	
December 21, 1998	1998	Non Firm	830	1017	1.47	
September 30, 1999	1999	Non Firm	1700	1730	0.5	
October 21, 1999	1999	Non Firm (Group 1)	1300	1800	5	
January 5, 2000	2000	Non Firm (Group 8)	1730	1930	2	
May 22, 2000	2000	Non Firm	1430	1637	2.07	
June 14, 2000	2000	Non Firm	12:00	1800	6	
June 15, 2000	2000	Non Firm (Groups 1, 2 3, 5)	1230	1830	6	
June 27, 2000	2000	Non Firm	1400	1900	5	
June 28, 2000	2000	Non Firm	1430	1800	3.5	
July 31, 2000	2000	Non Firm (Group 6)	1430	1930	5	
August 1, 2000	2000	Non Firm (Group 6)	1300	1900	6	
August 1, 2000	2000	Non Firm (Groups 1-7)	1330	1930	6	
August 2, 2000	2000	Non Firm (Group 6)	1300	1900	6	
August 2, 2000	2000	Non Firm (Groups 1-7)	1300	1930	6	
August 15, 2000	2000	Non Firm (Group 6)	1430	0:00	2.37	
August 16, 2000	2000	Non Firm (Group 6)	1430	1730	3	
August 16, 2000	2000	Non Firm (Groups 1-5, 7-8)	1530	1730	2	
September 13, 2000	2000	Non Firm (Group 6)	14:52	1635	1.43	
September 18, 2000	2000	Non Firm	1330	1630	3	
November 13, 2000	2000	Non Firm	1830	2000	1.5	
November 14, 2000	2000	Non Firm (Groups 1-5)	1730	1830	1	
November 15, 2000	2000	Non Firm (Groups 1-5)	1700	1815	1.15	
December 4, 2000	2000	Non Firm	1700	1900	2	
December 5, 2000	2000	Non Firm	1630	1836	2.06	
December 6, 2000	2000	Non Firm	1630	2015	3.45	
December 7, 2000	2000	Non Firm	7:00	808	1.08	Fist time Non Firm Program was called twice in one day
December 7, 2000	2000	Non Firm	1630	2030	4	
December 10, 2000	2000	Non Firm (Groups 1-5, 7-8)	1700	2200	5	Fist time Non Firm Program was called on the weekend
December 11, 2000	2000	Non Firm (Groups 1-5, 7-8)	1700	2300	6	
January 9, 2001	2001	Non Firm	1730	1815	0.45	
January 10, 2001	2001	Non Firm (Groups 1-5, 7-8)	1730	1934	2.04	
January 11, 2001	2001	Non Firm	645	1245	6	Non Firm Program was called twice on this day
January 11, 2001	2001	Non Firm	1630	1741	1.11	
January 16, 2001	2001	Non Firm	730	1330	6	Non Firm Program was called twice on this day
January 16, 2001	2001	Non Firm	1700	2123	4.23	
January 17, 2001	2001	Non Firm	500	1100	6	Fist time Non Firm Program was called three times in one day
January 17, 2001	2001	Non Firm	1105	1705	6	
January 17, 2001	2001	Non Firm	1710	2310	6	
January 18, 2001	2001	Non Firm	600	1200	6	Non Firm Program was called three times on this day
January 18, 2001	2001	Non Firm	1205	1805	6	
January 18, 2001	2001	Non Firm	1810	2210	4	
January 19, 2001	2001	Non Firm (Groups 1-5, 7-8)	530	1130	6	Non Firm Program was called twice on this day
January 19, 2001	2001	Non Firm (Groups 1-5, 7-8)	1135	1430	3	
January 20, 2001	2001	Non Firm (Groups 1-5, 7-8)	1000	1600	6	Non Firm Program was called twice on this day
January 20, 2001	2001	Non Firm (Groups 1-5, 7-8)	1605	1900	2.55	
January 21, 2001	2001	Non Firm (Groups 1-5, 7-8)	1330	1930	6	Non Firm Program was called twice on this day
January 21, 2001	2001	Non Firm (Groups 1-5, 7-8)	1935	2215	2.4	
January 22, 2001	2001	Non Firm (Groups 1-5, 7-8)	845	1445	6	Non Firm Program was called twice on this day
January 22, 2001	2001	Non Firm (Groups 1-5, 7-8)	1450	1920	4.5	
January 26, 2001	2001	Non Firm (Group 6)	1015	1615	6	
February 12, 2001	2001	Non Firm (Groups 1-5, 7-8)	1615	2100	4.45	
February 12, 2001	2001	Non Firm (Group 6)	1715	2100	3.45	
February 13, 2001	2001	Non Firm	1600	2100	5	
February 14, 2001	2001	Non Firm	930	1530	6	
February 15, 2001	2001	Non Firm	730	1330	6	Non Firm Program was called twice on this day
February 15, 2001	2001	Non Firm	1730	2130	4	
February 28, 2001	2001	Non Firm	1630	2230	6	

March 15, 2001	2001	Non Firm	1430	2030	6	
March 19, 2001	2001	Non Firm	945	2100	11.15	
March 20, 2001	2001	Non Firm	900	2100	12	
March 27, 2001	2001	Non Firm	1430	2200	7.5	
March 28, 2001	2001	Non Firm	1115	2300	11.45	
March 30, 2001	2001	Non Firm	1000	1600	6	
March 31, 2001	2001	Non Firm	1140	1740	6	
April 2, 2001	2001	Non Firm	950	1550	6	Non Firm Program was called twice on this day
April 2, 2001	2001	Non Firm	2000	2400	4	
April 3, 2001	2001	Non Firm	740	1340	6	
May 7, 2001	2001	Non Firm (Group 6)	1015	1615	6	
May 8, 2001	2001	Non Firm (Group 6)	1300	1815	5.15	
May 9, 2001	2001	Non Firm (Group 6)	1300	1612	3.12	
May 10, 2001	2001	Non Firm (Group 6)	1400	1557	1.57	
May 31, 2001	2001	Non Firm (Group 6)	1330	1830	5	
July 3, 2001	2001	BIP	1400	1800	4	
July 10, 2002	2002	Non Firm	1500	1715	2.15	
September 14, 2004	2004	Non Firm (Group 8)	1100	1700	6	
September 14, 2004	2004	BIP (Group 8)	1130	1530	4	
July 24, 2006	2006	Non Firm	1430	1800	3.5	
July 24, 2006	2006	BIP	1500	1800	3	
November 26, 2007	2007	Non Firm (Group 8)	1800	2100	3	
November 26, 2007	2007	BIP (Group 8)	1800	2100	3	
August 28, 2008	2008	BIP	1500	1700	2	Test Event
August 28, 2009	2009	BIP	1400	1600	2	Test Event
August 24, 2010	2010	BIP	1500	1700	2	Test Event
March 11, 2011	2011	BIP (Group 8)	735	808	30 min	
September 7, 2011	2011	BIP	1500	1700	2	Test Event
August 10, 2012	2012	BIP	1500	1700	2	Test Event
July 2, 2013	2013	BIP	1500	1900	4	Test Event
August 25, 2013	2013	BIP	1400	1800	4	Re-Test Event
February 6, 2014	2014	BIP	1515	1915	4	All Sublaps
April 17, 2014	2014	BIP	1400	1800	4	Re-Test Event

*When there is a parenthetical the Program was group locational dispatch

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT 5

CAISO DEMAND RESPONSE RESOURCE USER GUIDE

California ISO
Your Link to Power

CAISO Demand Response Resource User Guide

Guide to Participation in MRTU Release 1

November 29, 2007

Version 3.0

Table of Contents

1 Introduction

In the September 21 2006 MRTU FERC Order[1], the CAISO was directed to work with market participants to present additional opportunities for Demand Response resources to participate in the CAISO market and to work with Load Serving Entities ("LSEs") to develop methods for the accounting of expected demand response within Residual Unit Commitment (RUC procurement.

In this regard, five key demand resource working groups have been formed to help meet this important objective.
The five working groups are:

Demand Response Participation in MRTU Release 1

- Lead agency- CAISO

Demand Response Participation in MRTU Post Release 1

- Lead agency- CAISO

Demand Resource Product Specification

- Lead agency- CEC

Infrastructure for Demand Resources

- Lead agency- CEC

Vision for Demand Resources

- Lead agency- CPUC

Each working group has specific objectives and resulting deliverables to produce with the over-arching objective being to enable greater participation from demand resources in the wholesale power markets.

This User Guide was developed in response to this directive and is a result of the CAISO working collaboratively with the CPUC, CEC and Demand Resource Providers to advance the integration of demand resources into the CAISO's wholesale market design

[1] 116 FERC 61,274

and grid operations through the Demand Response participation in MRTU Release 1 Working Group.

The CAISO MRTU Release 1 software will include limited functionality and ability for demand resources to participate directly in the CAISO wholesale markets. The CAISO markets for MRTU Release 1 will accommodate pump storage hydro units and aggregated hydro pumps that participate in the CAISO markets as Participating Load. Although the design is limited, it may be possible for other types of demand resources to fit into this model allowing them to provide the CAISO imbalance energy as well as non-spinning reserve as a participating load. However, as currently designed the existing Demand Response Programs managed by the three Investor Owned Utilities in California, PG&E, SCE and SDG&E and others, are not compatible with the CAISO's current Participating Load model. Since the existing Demand Response Programs provide valuable DR, but are not compatible with the current Participating Load model, the MRTU Release 1 Working Group was formed to develop a process by which the CAISO can immediately account for benefits provided by these Demand Response Programs in the CAISO energy markets.

1.1 About this Guide

The purpose of this user guide is to document a process that describes how Demand Response Programs and Demand Response resources can be incorporated into MRTU Release 1. The Guide focuses on DR being in MRTU as Non-Participating Load. This user guide is intended to be a living document that will be updated periodically to reflect added functionality and enhancements that further eliminate the manual processes described herein and seek to seamlessly integrate demand response resources into the CAISO's markets and its grid operations.

This user guide is the result of a collaborative effort by Demand Response Providers as part of the MRTU Release 1 Working Group. Further refinement to this guide is expected with the initiation of the MRTU Post Release 1 working group and its efforts.

1.2 CAISO Requirements

The entity submitting Demand Response data and/or bids to the CAISO must be a certified Schedule Coordinator.[2] A Scheduling Coordinator is an entity certified by the CAISO for the purposes of undertaking functions such as scheduling, bidding, and settlement, and as further defined in Section 4.5.3 of the CAISO Tariff. In this document Scheduling Coordinators that submit Demand Response data to the CAISO will be referred to as Demand Response Providers.

2 Day-Ahead Demand Response Programs and Day-Of Programs called Day-Ahead

Day-Ahead Demand Response Programs are initiated by Demand Response Providers and are triggered based on various conditions such as the day-ahead forecasted temperature, day-ahead forecasted demand and high price forecasts. Customers are typically notified the day prior to the event day that the program will be triggered. This section also applies to Day-Of DR programs when they are called the Day-Ahead.

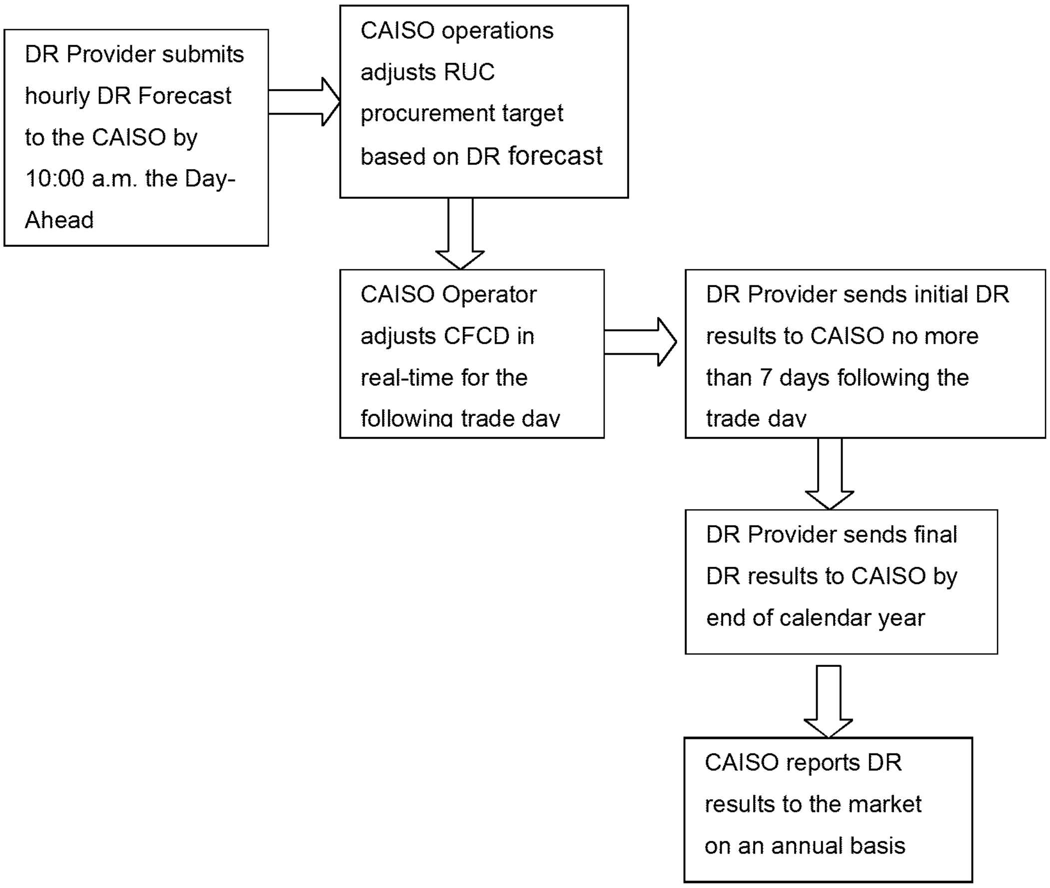
2.1 Process for Day-Ahead Programs

The following sections describe in detail the process for how Day-Ahead Demand Response Programs will participate and be accounted for in the CAISO markets for MRTU Release 1.

The overall process is shown graphically below. Each box that represents a process is explained in detail in the sections that follow:

[2] Other models for how demand response resources are delivered to the CAISO may evolve with time, e.g. the Curtailment Service Provider model used in some eastern ISOs; however, no changes to the Scheduling Coordinator model are contemplated at this juncture given regulatory policy, settlement, and technical barriers that must first be addressed.

Process Overview Day-Ahead Programs:



2.2 Submission of Demand Response (DR) Forecast

Since Demand Response resources will not participate in the CAISO market in Release 1 through an explicit market bid, the CAISO will need to be notified via a manual process using an Excel spreadsheet when a Demand Response Provider plans to call on a DR Program. Each Demand Response Provider will submit a spreadsheet to the CAISO. The DR forecast is a best estimate by the Demand Response Provider based on historical performance and other factors. In the future these estimates may be standardized to be based on an agreed upon load impact protocol that is approved by the CPUC as described in Section 5. The forecast is broken out by Demand Response Program by hour. In the future, the Demand Response Forecast will also be required to be broken out by RUC Zone. Initially, in 2008, the RUC zones will consist only of the UDC areas and MSS areas. Therefore,

SB_GT&S_0092311

the Demand Response forecast will be required by UDC area and will not need to be defined more granularly.

In the future as the CAISO's forecasting ability improves and becomes more granular there may be modifications to the existing RUC zones. These modifications will be communicated to stakeholders and the BPM for Market Operations will be updated with the new information. Sufficient time will be provided for the Demand Response Providers to adjust their systems and programs to provide this information by the new RUC zones. Once the CAISO's RUC zones become more granular, it will be required to submit the Demand Response forecast broken out by specific RUC Zone rather than the larger UDC area so the RUC procurement target can be adjusted based on the location of the Demand Response within the specific RUC Zone. The Daily DR Forecast Spreadsheet will be updated as these changes are made.

The CAISO has defined the following RUC Zones for MRTU Release 1:

- PG&E UDC
- SCE UDC
- SDG&E UDC
- NCPA MSS
- Anaheim
- Pasadena
- Azusa
- Banning
- Colton
- Riverside
- Vernon
- State Water Project

The process for submitting the Demand Response Forecast to the CAISO is as follows:

1. Each day that a Demand Response Provider is planning to call a DR program, it will fill out the Excel spread sheet "DR Price Responsive Program Forecast.

2. The spreadsheet should include all of the Demand Response Provider's Day-Ahead and Day-Of Price Responsive Programs even if they are not being called. If a Day-Ahead DR event is called, the Demand Response Provider will fill out the data that pertains the to the specific DR Program that will be called no later than 10 a.m. the Day-Ahead which corresponds to the Day-Ahead Market close time.

Example of Demand Response Forecast

Event Date	September 4, 2007							
Demand Response Provider	Load Curtailment Inc.							
Programs	**Program Type**	**# of Accounts**	**Trigger**	**Date/Time Published**	**HE12 MW**	**HE13 MW**	**HE14 MW**	**HE15 MW**
Demand Bidding Program	Day Ahead	225	Heat Rate Exceed 15K BTU	9/3/2007 9:02		40.2	25.4	32.5
Critical Peak Pricing Program	Day Ahead	42	Heat Rate Exceed 15K BTU	9/3/2007 9:02		25	25	40
Capacity Bidding Program	Day Ahead		Heat Rate Exceed 15K BTU					
Third Party Contract	Day Of		CAISO Flex Alert					
Demand Bidding Program	Day Of		CAISO Stage 1					
Capacity Bidding Program	Day Of		Heat Rate Exceed 15K BTU					
Total Price Response MW						65.2	50.4	72.5

3. Email Daily DR Forecast to the following CAISO email addresses:

   Shift Supervisors: CISOSS@caiso.com or ShiftSupervisors@caiso.com

   Day-Ahead Market: CAISOMktOps@caiso.com

   Hour-Ahead Market: MarketOpsHourAhead@caiso.com

   Also cc: JGoodin@caiso.com;GPerez@caiso.com;BSK@cpuc.ca.gov

Please see Attachment A for the DR Price Responsive Program Forecast Spreadsheet.

2.3 Accounting for Demand Response in the RUC Process

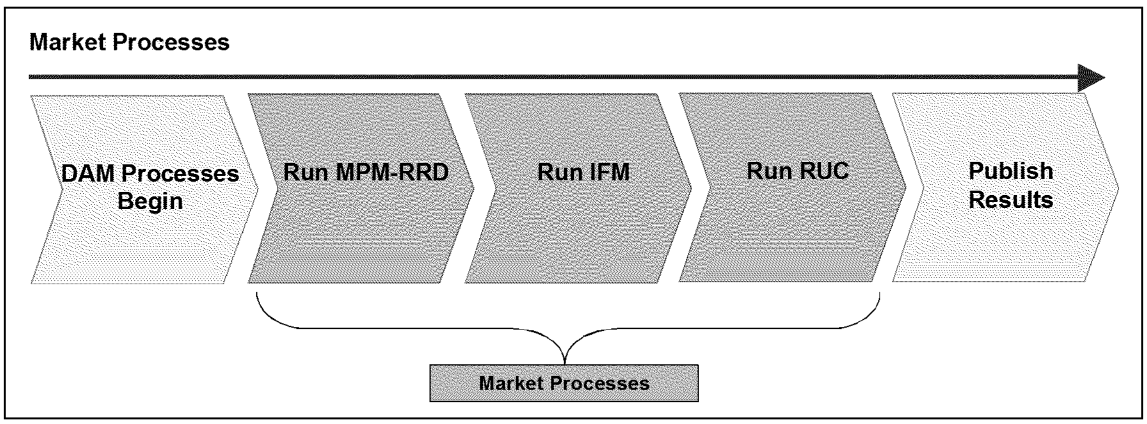
The purpose of the RUC (Residual Unit Commitment) is to procure additional capacity in the Day-Ahead Market that is required to meet the CAISO forecast of CAISO demand above what was committed in the Integrated Forward Market (IFM). The RUC process runs after the IFM is complete. See *Figure 1* below for CAISO Day-Ahead processes. The RUC process is based on specific requirements for serving expected CAISO Demand less any Demand scheduled in the IFM. These requirements are embedded in the RUC procurement target which is based on the CAISO Forecast of CAISO Demand (CFCD) and are established prior to the RUC run. The RUC procurement target is based on the difference between CFCD and the IFM Energy Schedule for each Trading Hour of the next Trading Day

The RUC process determines any incremental unit commitments and procures capacity from RUC Availability Bids to meet the RUC procurement target. Capacity selected in this process is awarded RUC Availability, and is required to be bid in and made available to the Real-Time Market.

The RUC procurement target is manually configurable by the CAISO operator and may be adjusted up or down based on various requirements.

Please see the *"BPM for Market Operations"* section 6.7.2 for a description of situations where the RUC procurement target may be adjusted up or down by the CAISO operator. The BPM for Market Operations may be accessed at the following link: http://www.caiso.com/1c0f/1c0fec1830fa0.doc

Figure 1 – CAISO Day-Ahead Market Processes



Since Demand Resources, other than Participating Load, will not explicitly participate in the market in MRTU Release 1, the CAISO will manually adjust the RUC procurement target by adjusting the CFCD in the relevant RUC Zone based on the Day-Ahead Demand Response Forecast submitted by the Demand Response Providers' as described in Section 2.2 above. The RUC Procurement Target will be adjusted based on the MW quantity of forecasted DR submitted to the CAISO. The accounted for Demand Response will allow the CAISO to adjust the RUC procurement target downwards resulting in less RUC procurement. The CAISO must receive the Demand Response forecast by no later than10:00 a.m. the Day-Ahead in order to adjust the RUC

Procurement Target. As described in Section 2.4 below, if the Demand Response forecast is received after 10:00 a.m only the CFCD for the Real-Time market will be adjusted for each hour the program is forecasted to be initiated.

Any changes to the RUC Procurement Target and reasons for the change will be logged by the CAISO Operator and communicated to the market in the form of a report that will be posted on the CAISO website. It is still to be determined the format of the report and how often it will be posted. This guide will be updated with more detailed information when it becomes available.

2.4 Accounting for Demand Response in the Real-Time Market Unit Commitment Processes

The Real-Time Market ("RTM") consists of three processes working together: STUC, RTUC and RTED. Since non-participating load bids are not accepted into the RTM, the RTM and its processes use the CAISO Forecast of CAISO Demand (CFCD) to clear with supply in each of the processes. Please see Figure 2 below for a description of the CAISO Real-Time processes.

Figure 2 – CAISO Real-Time Processes

Element	Acronym	Detail
Market Power Mitigation	MPM	Applies to all Bids received by T-75 before the operating hour
Hour-Ahead Scheduling Process	HASP	Executes at T – 67.5 and looks at the next Trading Hour: -Pre-dispatches Non-Dynamic System Resources -Pre-dispatches AS on the interties -Provides Advisory Schedules in 15-minute increments
Short-Term Unit Commitment	STUC	Executes hourly at T – 52.5. Looks ahead 4.5 hours to meet the CAISO demand forecast in each 15-min interval and commits Short and Medium Start Units if commitment decision can not be postponed for the next STUC/RTUC execution. Otherwise commitment decisions are advisory.
Real-Time Unit Commitment	RTUC	Executes every 15 – min at the middle of each quarter of the hour. Looks out between four and

		seven 15-minute intervals to ensure there is sufficient Capacity to meet the Demand. - Commits and de-commits Short Start and Fast Start Units - Procures additional AS
Real-Time Economic Dispatch	RTED	Executes every 5 minutes to meet the Imbalance Energy requirement

Since the CAISO generates new load forecasts for the RTM, the Demand Response MWs that were forecasted and accounted for in the RUC procurement target in the Day-Ahead market will be accounted for in Real-Time by reducing the CFCD for the hours that the Demand Response Program will be initiated. This ensures that the DR is carried through and accounted for when the CAISO commits additional generating units in the RTM. For example, if a forecast for a Day-Ahead DR Program is submitted to the CAISO for trade day tomorrow for hour ending 12 through hour ending 17 the CAISO operator would adjust the CFCD for the Real-Time market for the same hours. The real-time processes run continuously so in this example assuming that T is 12:00 pm which is the first hour of the DR Program, the HASP process when it runs at T-67.5 looking out a trading hour in the future would be performing the hourly pre-dispatch of resources beginning 10:53 a.m. for hourly pre-dispatch of units starting from 12:00 p.m. (T) to T + 60 (1:00p.m.) The STUC process would run beginning at T – 52.5 (11:12 a.m.) for that same trade hour and would be committing units for the time horizon T – 15 minutes (11:45 a.m) through T + 240 (4:00 p.m). Therefore adjustments made the CFCD for hour ending 12 through 16 would be taken into account for this run and subsequent runs of the HASP and STUC processes. If the adjustment to the CFCD were made well in advance ,the STUC could see this adjustment to the CFCD as early as approximately 7:08 a.m. for Trading hour ending 7 looking out over a time horizon for unit commitment of T – 15 (7:45 am) to T + 240 (12:00 pm).

Depending on system conditions and the quantity of Demand Response provided the adjustment to the CFCD may or may not result in a change to Real-Time unit commitment.

3 Day-Of Price Responsive Demand Response Programs

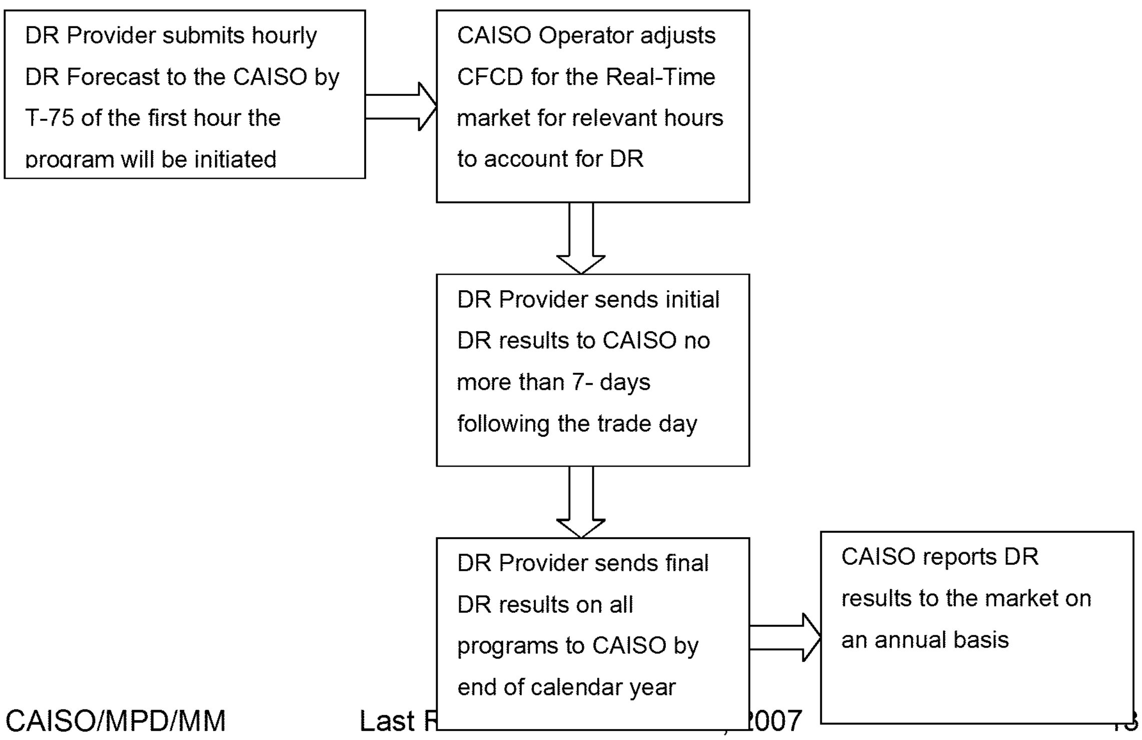
Day-Of Price Responsive Demand Response Programs are initiated by Demand Response Providers and may be initiated based on CAISO system conditions or other specific triggers such as forecasted load, expected heat rate indicator, forecasted high prices, CAISO Alerts or Warnings, forecasted or actual temperature, etc. CAISO declared system emergencies are covered under the Emergency Programs described in section 6 below.

Under Day-of Price Responsive Programs, customers are notified the same day the event will occur and, depending on the program, are given as much as 3 hours notice to as little as 15 minutes notice to curtail load.

The following sections describe in detail the process for how Day-Ahead Demand Response Programs will participate and be accounted for in the CAISO markets for MRTU Release 1.

The overall process is shown graphically below. Each box that represents a process is explained in detail in the sections that follow:

Process Overview – Day-Of Programs



3.1 Process for Day Of Programs

Demand Response Providers will fill out the DR Price Responsive Program spreadsheet with the relevant data for the Day-Of Program or programs being called and e-mail to the CAISO following the same process described in Section 2.2 above as soon as possible after an event is triggered, but no later than the Trading Hour minus 75 minutes (Real-Time Market close time).[3]

Demand Response Providers will report actual results to the CAISO using the process described in Section 5 below.

3.2 Adjustments for Day-Of Programs in the Day-Ahead and Real-Time Markets

The CAISO will adjust the CFCD based on the DR Forecast in Real-Time no later than T – 75 minutes for each hour that a program is scheduled to be initiated. This timing corresponds to the Real-Time Market close time. Depending on when the DR forecast is received the CAISO will adjust the CFCD for all hours or only a portion of hours the DR program is scheduled to be initiated. In order to adjust all hours the DR forecast will need to be received by the CAISO 75 minutes prior to the top of the first hour the program will be initiated. Any adjustments made to the CFCD either up or down will be logged by the CAISO operator. If conditions are such that a Demand Response Provider knows they will initiate a Day-of Program by 10:00 a.m. the Day-Ahead and sends that Demand Response forecast to the CAISO, the CAISO will adjust the RUC procurement target in the Day-Ahead Market as well as the Real-Time CFCD for the following day to account for the demand response. As described in Section 2.4 above, the real-time processes run continuously so the earlier the adjustment to the CFCD can be made will allow it to impact the various real-time processes that commit units over a longer time horizon such as the STUC and RTUC.

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3 For example, Trade Hour 10 begins at 0900 and ends at 1000. As such, trading for Trade Hour 10 ends at 0745, i.e. T-75 minutes before the Trade Hour.

4 Emergency Programs

Emergency Programs, also known as Interruptible or non-firm programs, are triggered based upon a CAISO declared Stage 2 or Stage 3 emergency or for a local transmission emergency. These programs may be initiated by the Demand Response Provider themselves or by request from the CAISO.

4.1 Process for Emergency Programs

Demand Response Providers will fill out the spreadsheet entitled DR Emergency Program Forecast shown in Attachment B, and e-mail to the CAISO following the process described in Section 2.2 above as soon as possible after an event is triggered.

The CAISO will continue to follow the process defined in CAISO Operating Procedure No E-511 when making a request to a Demand Response Provider to trigger an Emergency Program.

Since emergencies are unpredictable and emergency responsive programs are dispatched as a last resort grid reliability measure, the CAISO does not intend to adjust the RUC Procurement Target or the Real-Time CFCD to account for the Demand Response provided by these programs.

Estimated actual DR response will be recorded in a separate spreadsheet titled "DR Expected Results and submitted to the CAISO as described in Section 5.1 below.

5 Load Impact Protocols

Demand Response performance is determined by the Demand Response Provider based on the difference between the meter read and the calculated energy baseline. Currently, load impact protocols used to determine baselines may differ by program type and/or by the three primary Demand Response Providers, PG&E, SCE, and SDG&E. In the near future, there will likely be a need to agree to a set of load impact protocols applicable to determining Demand Response Program performance for CAISO operational use and purposes. This issue of appropriate and applicable load impact protocols is currently being addressed by the CPUC in the DR Rulemaking (R.07-01-041) proceeding.

For the purposes of reporting DR Performance to the CAISO on Day-Ahead and Day-Of Programs the three main Demand Response providers have agreed to use a 3 in 10 baseline where the hourly average is based on the three (3) highest energy usage days of the immediate past ten (10) similar days. The three (3) highest energy usage days are those days with the highest total kilowatt hour usages during the program hours. The past ten (10) similar days will include Monday through Friday, excluding holidays and will additionally exclude days when the customer was paid to reduce load on an interruptible or other curtailment program or days when rotating outages were called

These baseline methodologies will be further refined in the future.

5.1 Actual DR Performance

The actual DR response, based on application of the appropriate baseline methodologies (see Section 5), will be reported to the CAISO in a separate spreadsheet titled "DR Program Results". This spreadsheet will contain results for all programs by event date and by hour. This information will be sent to the CAISO within 7 days of the trade day after the event or as soon as possible thereafter.

If additional updates are required following the 7 day report to correct any significant variances, Demand Response providers will send an update to the CAISO and note the date of the revision in the template.

At the end of the calendar year Demand Response Providers will re-calculate and send final data for all programs by event date for the entire year to the CAISO using the same DR Program Results spreadsheet. The goal is for the data reported to the CAISO on DR Results to be consistent with what is reported to the CPUC and other regulatory agencies.

Sample of DR Program Results Spreadsheet

Demand Response Provider	Load Curtailment Inc.											
Programs	Event Date	Program Type	Trigger	# of Accounts	Event Start Time (PDT)	Event End Time	Last Modified Date	HE 01 MW	HE 02 MW	HE 03 MW	HE 04 MW	HE 05 MW
Demand Bidding Program	6/7/2007	Day Ahead	Heat Rate Exceed 15K BTU	225	12:00	20:00	6/18/2007			40.2	25.4	32.5
Critical Peak Pricing Program	6/7/2007	Day Ahead	Heat Rate Exceed 15K BTU	42	12:00	18:00	6/18/2007			8.1	8.4	8.6
Capacity Bidding Program	6/7/2007	Day Of	Heat Rate Exceed 15K BTU	16	14:00	16:00	6/18/2007					1.5
Third Party Contract	6/10/2007	Day Of	ISO Flex Alert	97	15:00	20:00	6/18/2007					
I6	6/12/2007	Emergency	ISO Stage 2	325	14:22	16:55	6/18/2007					352.0

Please see Attachment C for the DR Program Results spreadsheet.

6 Reporting DR Results to the Market

The CAISO proposes to publish the Demand Response results annually at the end of the calendar year after receiving the final DR results from providers.

The report would include the hourly DR forecasts, the MW reduced from the CAISO Forecast (CFCD), if applicable, and the final DR results. As Demand Response resources continue to play a larger role directly in the CAISO markets this report will be enhanced to show more data.

The CAISO will take appropriate steps in the publishing of the DR results to maintain the confidentiality of contracts. This includes having the DR Providers review the report before it is published.

6.1 Estimate of Demand Response Available MW

The Demand Response providers shall provide the CAISO with an estimate of the MW available in each DR program as necessary. The information shall be included with the Demand Response Forecast as an additional sheet in the workbook. This is for monthly planning information purposes only. The MW actually submitted when a DR program is called under Sections 2, 3 and 4 will supersede any estimate in this monthly planning submission. The document will also provide information on each of the programs including event limits (hours per call, calls per month and year, notification time, etc.)

7 Future Market Enhancements for Demand Response

The CAISO has formed a Demand Response Post Release 1 working group as discussed in Section 1 above, to address the future enhancements that will allow Demand Response resources to participate directly in the CAISO markets as dispatchable resources.

The design that is under consideration will allow demand resources, also known as Participating Load, to submit three-part bids similar to a generators' start-up, minimum load and multi segment energy bid that would consist of load curtailment cost, minimum load reduction cost, and a multi segment load energy bid. Under this full dispatchable demand resource model, the Participating Load will have the opportunity to participate directly in the Day-Ahead energy market, RUC, Non-Spinning Reserve, and the Real-Time Imbalance Energy Market.

For more information on future enhancements associated with Demand Response please refer to most recent Draft Straw Proposal entitled " Post Release 1 MRTU Functionality for Demand Response" posted on the CAISO website at the following link: http://www.caiso.com/1c91/1c919e0e11c30.pdf

8 References

Other documents that provide background or additional detail directly related to the *CAISO Demand Response Resource User Guide* are:

- BPM for Market Operations
- 5 – Year Market Initiatives Road Map
- Residual Unit Commitment Zones under MRTU
- Issue Paper – Post Release 1 MRTU Functionality for Demand Response
- CAISO Operating Procedure No E- 511
- The Market 201 Training Workbook

8.1 CAISO Contacts

Please contact Margaret Miller at mmiller@caiso.com or 916 608-7028 or John Goodin at jgoodin@caiso.com or 916 608 -7154 with questions or comments on the *Demand Response Resource User Guide.*

9 Glossary of Terms

Some but not all of the terms provided herein are defined terms in the CAISO Tariff. These tariff defined terms have been flagged with a (T). Other terms have been defined for the purpose of this user guide only.

Term	Definition
CAISO Forecast of CAISO Demand (CFCD)	The forecast of CAISO Demand made by the CAISO for use in the CAISO Markets

	(T)
Day-Ahead Demand Response Program	A program to provide a reduction in Demand that is initiated the day-ahead of the actual event
Day-Of Demand Response Program	A program to provide a reduction in Demand that is initiated the same day of the event.
Demand Response (DR) Forecast	a MW quantity of Demand Response expected to be delivered
Demand Response Program	A program to provide a reduction in Demand in response to specified conditions or circumstances, typically implemented by an LSE. (T)
Demand Resource Provider	Any entity that provides demand response programs, curtailable demand or services.
Demand Response Provider	A certified SC that submits DR data to the CAISO.
Demand Response (DR) Results	Actual MW Quantity of Demand Response delivered based on baseline and used to compare against DR forecast
Emergency Demand Response Program	Demand Response Programs that are initiated as a result of a local transmission emergency or when the CAISO calls a Stage 2 or Stage 3 emergency
Hour-Ahead Scheduling Process (HASP)	The process conducted by the CAISO beginning at seventy-five minutes prior to the Trading Hour through which the CAISO conducts the following activities: 1) accepts Bids for Supply of Energy, including imports, exports and Ancillary Services imports to be supplied during the next

	Trading Hour that apply to the MPM-RRD, RTUC, STUC, and RTD; 2) conducts the MPM-RRD on the Bids that apply to the RTUC, STUC, and RTD; and 3) conducts the RTUC for the hourly pre-dispatch of Energy and Ancillary Services. (T)
Integrated Forward Market (IFM)	The pricing run conducted by the CAISO using SCUC in the Day-Ahead Market, after the MPM-RRD process, which includes Unit Commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply and Demand Bids (T)
Participating Load	An entity, including an entity with Pumping Load, providing Curtailable Demand, which has undertaken in writing by execution of a Participating Load Agreement to comply with all applicable provisions of the CAISO Tariff, as they may be amended from time to time. (T)
Residual Unit Commitment (RUC)	The process conducted by the CAISO in the Day-Ahead Market after the IFM has been executed to ensure sufficient Generating Units, System Units, System Resources and Participating Loads are committed to meet the CAISO Forecast of CAISO Demand. (T)
Real-Time Unit Commitment (RTUC)	An application of the RTM that runs every 15 minutes and commits Fast and Medium-Start Units using the SCUC to adjust from Day-Ahead Schedules and HASP Intertie Schedules. (T)
Real-Time Economic Dispatch (RTED)	The mode of the Real-Time Dispatch that

	will optimally dispatch resources based on their Energy Bids, excluding Contingency Only Operating Reserves except when needed to avoid an imminent System Emergency. (T)
RUC Procurement Target	quantity to be procured in RUC based on CFCD
Scheduling Coordinator	An entity certified by the CAISO for the purposes of undertaking the functions specified in Section 4.5.3. of the CAISO Tariff (T)
Short Term Unit Commitment (STUC)	The Unit Commitment procedure runs at approximately T-52.5 minutes for a Time Horizon of approximately five (5) hours. The STUC determines whether some Medium Start Units need to be started early enough to meet the Demand within the STUC Time Horizon using the CAISO Forecast of CAISO Demand. The STUC produces a Unit Commitment solution for every 15-minute interval within the STUC Time Horizon and issues binding Start-Up instructions only as necessary. (T)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

REBUTTAL TESTIMONY OF LUKE A. TOUGAS

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REBUTTAL TESTIMONY OF LUKE A. TOUGAS

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 Opening Testimony submitted by the Natural Resources Defense Council (NRDC) regarding fossil-fueled Back-Up Generation (BUG), and Alarm.com and EnergyHub (Alarm.com/EnergyHub) regarding Demand Response (DR) program implementation issues.

B. Response to NRDC Opening Testimony

Q 2 Is the study cited by Mr. Bull (p. 2) representative of all DR programs offered in California?

A 2 No. The study cited by Mr. Bull is the same study I cite in my Opening Testimony (p. 7-2, lines 10-15). Mr. Bull characterizes this study as a "comprehensive study" which is not a correct statement. As the full title of the report indicates, the only DR programs covered in this study are the investor-owned utilities' (IOU) Base Interruptible Programs and Critical Peak Pricing programs. The study does not cover the IOUs' other DR programs. As I state in my Opening Testimony (p. 7-4, line 26 to p. 7-5, line 6), the California Public Utilities Commission (CPUC or Commission) should develop a full record on the use of fossil-fueled BUG for DR before making any decisions to limit the use of these technologies from providing DR.

Q 3 Is Mr. Bull correct in asserting that the IOUs were not in compliance with Decision 11-10-003, when the study was conducted in 2010, (pp. 2-3)?

A 3 No. Ordering Paragraph (OP) 3 of Decision 11-10-003 directed the Energy Division (ED), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) to consult to identify data on how customers intend to use BUG and identify the amount of DR provided by BUG when enrolling new customers in, or renewing DR programs. The ordering paragraph focuses on gathering data. It does not condition DR qualification for Resource Adequacy (RA) credit to not using fossil-fueled emergency BUG, nor does it set a deadline. Moreover, Decision 11-10-003 was issued a year after the study, and had no effect prior to the Commission vote approving the decision.

Q 4 Do you agree with Mr. Bull's contention that "without real time metering or comparable monitoring and tracking of BUG usage, enforcement of Decision 11-10-003 will remain extremely limited"?

A 4 No. No enforcement action has been taken because, as I cite on p. 7-3, lines 5-10 of my Opening Testimony, the Commission has not adopted any changes to the RA rules regarding the use of fossil-fueled BUG for DR. As I stated in my Opening Testimony, page 7-3, potential changes to RA rules related to fossil-fueled BUG for DR were deferred to a future RA proceeding. Thus there is no Commission-mandated program for oversight of fossil-fueled BUG, so it is premature for Mr. Bull to assert that the Commission should require real-time metering or comparable tracking for BUG.

C. Response to Alarm.com and EnergyHub

Q 5 Do you have rebuttal to the testimony of Seth Frader-Thompson, who is testifying on behalf of Alarm.com and EnergyHub?

A 5 Yes. Alarm.com/EnergyHub state on page 3 of their Opening Testimony that they are focused on integrating residential and small commercial customers into existing and future DR programs. On page 5, they propose that consumer-owned resources be aggregated directly into the market, without the requirement to work through a utility. I point out that under the recently-approved Direct Participation rules (Electric Rule 24 for PG&E), for a customer to be aggregated and participate in the California Independent System Operator (CAISO) market, it will need to be registered with the CAISO. This will require working through the customer's Load Serving Entity, which for a bundled-service customer will be an IOU. The IOUs' applications for implementation of their Direct Participation rules will be filed on June 2, 2014. PG&E's application will include information on the timing and scope of implementation of Electric Rule 24 for residential customers. PG&E supports residential customer participation to provide DR in the CAISO market, but the timing and scope will be dependent on the outcomes of these applications.

Q 6 On page 8, Mr. Frader-Thompson recommends an incentive of $50 per year to be paid to the aggregators for every enrolled customer, for as long as the customer remains in the DR program. Do you agree?

A 6 No. Specific incentives like a per-customer payment by the IOU to the aggregator are a matter of program design that should be considered when the specific program is developed and cost effectiveness can be analyzed.

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CHAPTER 4

REBUTTAL TESTIMONY OF STEVEN R. HAERTLE

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REBUTTAL TESTIMONY OF STEVEN R. HAERTLE

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 Opening Testimony regarding cost recovery that was presented by the Direct Access Customer Coalition/Alliance for Retail Energy Markets (DACC/AReM or DACC) and Marin Clean Energy (MCE).

B. Response to DACC Opening Testimony

Q 2 Please summarize DACC and MCE's recommended cost recovery for Demand Response (DR) programs.

A 2 Both DACC and MCE recommend that all DR program costs be recovered via generation rates. Consequently, all DR program costs would only be allocated to and paid by investor-owned utilities' (IOU) bundled customers.

Q 3 What is DACC's rationale for this recommendation?[1]

A 3 DACC's rationale differs depending on whether a DR program is deemed a Supply Resource (SR) or a Load Modifying Resource (LMR).

Q 4 What is DACC's rationale for SRs?

A 4 DACC asserts that DR programs defined as a SR are a substitute for generation supplies. DACC cites comments by the California Independent System Operator (CAISO) and the Federal Energy Regulatory Commission to define, operate, dispatch or equate the value of DR programs as generation substitutes. Consequently, DACC recommends that all DR programs defined as SR are recovered via generation rates, which would only be recovered from bundled IOU customers.

Q 5 What is DACC's rationale for LMRs?

A 5 DACC explains that some DR programs defined as a LMR may exclude Direct Access (DA) and Community Choice Aggregation (CCA) customers, may provide Resource Adequacy (RA) credits to an IOU, or may have

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1 Since DACC/AReM and MCE's positions on cost recovery are essentially the same, the remainder of this rebuttal testimony will refer to "DACC."

"generation-like function[s], such as peak shifting." Under DACC's proposal, the presence of any one of these attributes would trigger program cost recovery by generation rates, which would only be recovered from bundled IOU customers.[2]

C. DACC Offers Conflicting Criteria for Allocating DR Program Costs to Either Generation or Distribution Rates

Q 6 DACC's primary argument for LMR cost recovery via generation rates cites Decision 12-12-004. Would you please summarize the California Public Utilities Commission's (CPUC or Commission) decision regarding cost recovery in this decision?

A 6 In Decision 12-12-004, the Commission concluded that DA and CCA customers, who are not participating in San Diego Gas & Electric Company's (SDG&E) dynamic pricing tariffs, should not pay the implementation costs for such tariffs. Accordingly, SDG&E dynamic pricing program implementation costs are recovered from bundled customers via generation rates.

Q 7 How would DACC apply Decision 12-12-004's cost recovery to DR program cost recovery?

A 7 DACC recommends that costs for DR programs open to only bundled service customers be recovered through generation rates. In its opening testimony, DACC cites Decision 12-12-004 (emphasizing the final sentence below):

> We are persuaded by the arguments of the Direct Access Parties that requiring the customers of CCAs and ESPs, who cannot enroll in SDG&E's dynamic pricing tariffs, to pay the costs of implementing those tariffs, is not consistent with cost causation principles, and would not be reasonable. … Further, even if customers could move easily back and forth between different service providers, a customer is not able to take advantage of SDG&E's dynamic pricing while taking commodity service from any provider other than SDG&E. As a result, charging customers of other LSEs to implement these tariffs, or even charging them for the incremental costs of implementing or maintaining tools supporting these tariffs (such Web sites or additional customer service), would be charging them for costs that they do not incur and that do not significantly benefit them.
>
> When or if customers choose to move back to SDG&E bundled service, they would bear their share of the costs adopted in this proceeding

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[2] DACC notes that a DR program that was open to all customers (bundled, DA, and CCA) and provided distribution system benefits could be recovered via IOU distribution rates.

> under their bundled rates. The possibility that customers of other LSEs could use Web-based tools supported by dynamic pricing implementation funds in their decision-making, or could switch to bundled service and dynamic rates in the future, is not sufficient to convince us that the costs of developing and implementing these tools should be collected from those customers. … This conclusion is similar to the Commission's conclusion in D.02-11-022. For these reasons, we require that the costs of SDG&E's dynamic pricing decision be recovered from all bundled customers through generation rather than distribution rates.[3]

Q 8 When customers are eligible for a Pacific Gas and Electric Company (PG&E) DR program (that is, they can participate in these programs regardless of their energy supplier), should they pay for these programs via distribution rates?

A 8 Yes. When a customer is eligible for a DR program, the IOU incurs costs (including administrative and incentive costs) to make this program available to them. Decision 12-12-004 (per the citation above) notes that such costs are indeed incurred when a customer is eligible for SDG&E's dynamic pricing program. Hence, when a customer is eligible for an IOU's DR programs, the customer should help pay the costs of the DR programs.

Q 9 Which PG&E DR programs (both event-based and enabling programs) are open to bundled, DA, and CCA customers?

A 9 The following table shows customer eligibility for PG&E DR programs:

[3] D.12-12-004, pp. 52-53.

TABLE 4-1
PACIFIC GAS AND ELECTRIC COMPANY
DEMAND RESPONSE PROGRAM CUSTOMER ELIGIBILITY – DA AND CCA ELIGIBILITY

	Eligible for DR Program?	
Program	Direct Access (DA)	Community Choice Aggregation (CCA)
Base Interruptible Program	Yes	Yes
Optional Binding Mandatory Curtailment	Yes	Yes
Scheduled Load Reduction Program(a)	No	No
Capacity Bidding Program	Yes	Yes
Demand Bidding Program	Yes	Yes
Aggregator Managed Portfolio	Yes	Yes
SmartAC™	Yes	Yes
Auto DR	Yes	Yes
Technical Incentives	Yes	Yes
DR Emerging Technology	Yes	Yes
Permanent Load Shifting	Yes	Yes
Peak Day Pricing	No	No
SmartRate™	No	No

(a) There are no customers on Scheduled Load Reduction Program, and the program is capped at 0 megawatt. Decision 09-08-027 states "This program is legislatively mandated and so cannot be discontinued." (Section 10.1.3, p. 41.)

Q 10 The table above indicates that DA/CCA customers may not enroll in dynamic pricing programs, and Scheduled Load Reduction Program. Should these costs be excluded from recovery via distribution rates?

A 10 No. As explained in Section E below, the recovery of costs for dynamic pricing is appropriately reviewed in General Rate Case Phase I (GRC Phase I) proceedings, now that initial implementation has been approved in past decisions. In GRC Phase I, they are part of customer service costs, and appropriately recovered in distribution rates.

Q 11 As noted above, DACC also recommends that DR programs classified either as: (1) SR or (2) LMR receiving a RA credit are effectively electric generation substitutes, and, therefore, should be allocated to generation rates. Is DACC's recommendation consistent with the directive in Decision 12-12-004?

A 11 No. Decision 12-12-004 finds that DA and CCA customer eligibility for SDG&E dynamic pricing programs determines the cost incurrence and allocation to either generation or distribution rates.[4] Since DA/CCA service and bundled dynamic rate service are mutually exclusive, Decision 12-12-004 also concludes that a DA/CCA customer cannot incur the IOU's dynamic pricing costs while taking commodity service from a non-IOU LSE. Again, citing the Decision 12-12-004 above:

> Further, even if customers could move easily back and forth between different service providers, a customer is not able to take advantage of SDG&E's dynamic pricing while taking commodity service from any provider other than SDG&E.[5]

DACC cannot have it both ways. In other words, it cannot take a DR program that is open to DA/CCA customers (to be recovered via distribution rates per Decision 12-12-004), simply label it as "generation" or "generation-like," and then allocate these costs only to bundled customers.

Q 12 Could you provide an example of DACC's inconsistent approach?

A 12 Yes. Table 4-1 above shows that DA and CCA customers are eligible for the Aggregator Managed Portfolio (AMP) program. Additionally, as noted in my opening testimony (Table 8-1), AMP incentives (averaging about $10.0 million annually) are recovered via generation rates. AMP administration costs (approximately $0.4 annually) are recovered via distribution rates.

However, 96 percent of the annual AMP program costs are only recovered from bundled customers. This clearly demonstrates a subsidy from bundled customers to the DA and CCA customers who are eligible to participate in the AMP program.

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4 D.12-12-004, FOF 31 and COL 11.

5 D.12-12-004, p. 53.

Q 13 When customers are not eligible for a PG&E DR program, should they pay for these programs via distribution rates?

A 13 Yes. Notwithstanding Decision 12-12-004's cost allocation for SDG&E's dynamic pricing programs, DR programs may provide system and local grid reliability benefits (as some programs may be called locally). In addition, as noted in California Large Energy Consumers Association's (CLECA) and PG&E's opening testimony, DR load reductions reduce the market clearing prices in CAISO's wholesale markets.[6] This lower market clearing price benefits all customers, including customers who are not participating in DR programs.

Additionally, PG&E has demonstrated in previous testimony before the Commission that program participation, in and of itself, is not the sole basis for allocating DR costs. In both Application 08-06-003 and Application 11-03-001, PG&E noted that bundled residential, small commercial, small agricultural and streetlight customers were not able to participate in the PeakChoice™ or Base Interruptible Programs, yet they have funded these programs via their distribution rates.[7]

D. DR Programs, Since Their Inception, Focus on Providing a Customer Service (Via Bill Reductions) and Have Never Been a Procurement Function

Q 14 Throughout its testimony, DACC contends that DR program costs are a direct substitute for generation and should be allocated to generation rates. What was the initial impetus for DR programs based on your experience?

A 14 PG&E implemented DR programs in the early 1980's to help customers control their energy costs and bills. At that time, DR programs focused on air conditioning direct load control (now SmartAC), emergency reliability programs (formerly Schedule A-21 interruptible, then Schedule E-20 non-firm and now Base Interruptible Program), and Time-of-Use programs to provide customers optional programs and rates to reduce their peak demand in exchange for financial incentives.

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6 CLECA Opening Testimony, p. 45 and PG&E Opening Testimony, Appendix C.

7 Application 08-06-003, Pacific Gas and Electric Company Rebuttal Testimony, pages 6-1 to 6-2, and Application 11-03-001, Pacific Gas and Electric Company Rebuttal Testimony, page 11-3.

Q 15 Does helping customers reduce and control their energy costs continue to be a focus of PG&E DR programs?

A 15 Yes.

Q 16 Which functional organizations have administered and operated PG&E DR programs since their inception?

A 16 DR program administration and operations were implemented within the Regulatory Affairs function at PG&E in the early 1980's. In the 1990's, this function was transferred to the Customer Care function and remains there. Costs incurred in these functional organizations are allocated to distribution rates.

Q 17 Has PG&E's energy procurement and supply organization ever implemented or operated DR programs?

A 17 No they have not.

Q 18 Are there additional DR program costs – beyond program administration and incentive payments – incurred on the behalf of eligible customers (including DA and CCA customers)?

A 18 Yes, there are Evaluation, Measurement, and Verification, System Support Activities, Core Marketing and Outreach, and Integrated Program costs incurred to the programs listed in Table 4-1 above. These costs are appropriately recovered via distribution rates from all customers.

E. Dynamic Pricing Programs Costs and Recovery Are Appropriately Reviewed in General Rate Cases

Q 19 Are the costs and revenue requirements of Dynamic Pricing programs (Critical Peak Pricing, Peak Day Pricing, SmartRate) reviewed in the IOUs' DR program cycle budget applications?

A 19 No, they are not. PG&E's dynamic pricing implementation costs were authorized by the Commission in Decision 10-02-032 for recovery via the Dynamic Pricing Memorandum Account (DPMA), which is allocated to distribution rates, and Decision 06-07-027 for SmartRate. PG&E will recover total implementation costs up to $23 million in DPMA from 2014 through 2017. After 2013, PG&E has proposed in its current 2014 GRC Phase I application (A.12-11-009) to recover approximately $10 million in on-going dynamic pricing costs in distribution rates annually. A decision in Application 12-11-009 is pending.

Q 20 Is it appropriate to review the allocation of dynamic pricing costs in this rulemaking?

A 20 No, such review is not pursuant to the Commission's directive in Decision 10-02-032 and pending outcome in Application 12-11-009 and Application 13-04-012.

PACIFIC GAS AND ELEC TRIC COMPANY

APPENDIX A

REBUTTAL TESTIMONY OF

DR. ALEX PAPALEXOPOULOS

PACIFIC GAS AND ELECTRIC COMPANY
REBUTTAL TESTIMONY OF
DR. ALEX PAPALEXOPOULOS

Q 1 What is the purpose of your rebuttal testimony?

A 1 My rebuttal testimony responds to the Opening Testimony of Mr. Neil Millar representing the California Independent System Operator (CAISO).

Q 2 Do you agree with Mr. Millar's statement in his Opening Testimony (page 7, line 15 to page 9, line 18) that demand response (DR) needs to be controlled through the CAISO's economic dispatch system?

A 2 No. In his Opening Testimony Mr. Millar states that the shortcomings of the manual notification process fall into these three general categories:

1. Transparency of location – tracking locations of resources and manually overlaying those impacts within the security-constrained dispatch of the market is overly complex in today's operating environment, and locations are critical in meeting local reliability needs.
2. Better accuracy on availability on a day ahead and real time basis – the known quantities of DR available are also critical in both time frames.
3. Price discovery – the price impacts of the DR resources can only properly be represented through market participation and directly contributing to price formation.

In my Opening Testimony (page A-7, line 22 to page A-8, line 29), I describe in detail how Day-Ahead DR and Day-Of DR programs are incorporated through a manual process, as Load Modifier Resource DR, into the CAISO market processes consistent with the CAISO Demand Response Resource User Guide Version 3.0. I further present possible ways to improve the coordination of Load Modifying Resource DR with the CAISO's processes and procedures. These represent initial ideas that should be considered for improvement, but any final decision to make these changes would require further investigation by the CAISO and the stakeholders.

With respect to Mr. Millar's concern about the transparency of location, I certainly agree that locations are critical in meeting local reliability needs. I also agree that overlaying the impacts of Load Modifying Resource DR into the CAISO processes is complex. However, the restrictions imposed by the current CAISO market architecture on Supply Resource DR to participate in the CAISO wholesale energy market with respect to resource location management, and handling of the configuration and size of aggregations is even more complex and more onerous. This greater complexity may contribute to limiting wide participation of DR programs as Supply Resource DR in the CAISO wholesale energy market, and makes it difficult for Load-Serving Entities (LSEs)/Demand Response Providers (DRPs) to increase their portfolio and build resources of sufficient size for bidding in the market. Forcing LSEs/DRPs to invest the required funds to adapt their IT infrastructure and business processes to ensure full participation of their Load Modifying Resource DR programs as Supply Resource DR is not advisable because such a decision is not justified on a cost/benefit analysis basis. Further, any requirement that Load Modifying Resource DR be bid into the CAISO as Supply Resource DR will tend to increase program costs and could potentially discourage participation since such participation would be less likely to be justified on an economic basis.

With respect to Mr. Millar's concern about the accuracy of the resource availability, experience from the current performance of the Load Modifying Resource DR of the LSEs/DRPs gives strong credence to the claim that Load Modifying Resource DR is as reliable and predictable as Supply Resource DR. For an example, please refer to the Rebuttal Testimony of Mr. Abreu, Chapter 2.

In general, as I presented in my Opening Testimony, many DR programs are weather sensitive, so providing accurate availability predictions on a day-ahead and real-time basis is sometimes challenging regardless of whether they are Load Modifying Resource DR coordinated with the CAISO or Supply Resource DR bid in the CAISO markets. In other words, the underlying issues related to resource availability apply equally to Load Modifying Resource DR and Supply Resource DR.

In my Opening Testimony (page A-10, line 12 to page A-20, line 31) I offer some ideas related to resource availability that, if implemented, may reduce the cost and complexity of the participation of Supply Resource DR into the CAISO's wholesale energy market. This exhibit is not intended to provide a complete treatment of this subject but is intended to provide some initial guidance for recommendations.

With respect to Mr. Millar's concern about the price formation issue, as I presented in my Opening Testimony (page A-7, line 22 to page A-8, line 29), Load Modif ying Resource DR directly a ffects the load that the energy markets serve and thus the prices in these markets.

The net effect of the Load Modif ying Resource DR actions is a less steep, less deep and flatter net load curve that requires a smaller amount of flexible capacity and a smaller number of peaking units for balancing. This means that Load Modif ying Resource DR actions directly impact the type and the number of conventional generation resources that are needed to balance the CAISO's net load curve. Therefore, Load Modif ying Resource DR, even though not bid in like generation in the CAISO market, directly participates in the market since their action directly result s in load changes. As a result, one can conclude th at Load Modif ying Resource DR directly contributes to the price formation in the CAISO energy market.

In summary, I conclude that:

1. Current market rules related to resource location management, and handling of the configuration and size of aggregations of Supply Resource DR bid in the wholesale CAISO energy market is even more complex and more onerous than the current process of tracking and overlaying DR impacts into the CAISO processes.
2. The underlying issues related to resource availability apply eq ually to Load Modifying Resource DR and Supply Resource DR.
3. Load Modifying Resource DR contributes to price formation in the CAISO energy market and helps reduce the CAISO energy market price.

PACIFIC GAS AND ELEC TRIC COMPANY

APPENDIX B

REBUTTAL TESTIMONY OF DR. JAY ZARNIKAU

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.

Rulemaking 13-09-011

PHASE 3

REBUTTAL TESTIMONY OF
DR. JAY ZARNIKAU
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY

MAY 22, 2014

BEFORE THE
PUBLIC UTILITIES COMMISSION OF CALIFORNIA

REBUTTAL TESTIMONY OF
DR. JAY ZARNIKAU
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY

Q.1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A.1. My name is Jay Zarnikau. My business address is 1515 Capital of Texas Hwy, South, Suite 110, Austin, Texas.

Q.2. ARE YOU THE SAME JAY ZARNIKAU WHO FILED DIRECT TESTIMONY IN THIS DOCKET ON BEHALF OF PACIFIC GAS AND ELECTRIC COMPANY (PG&E)?

A.2. Yes, I am.

Q.3. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A.3. My Rebuttal Testimony responds to certain statements in the Phase 3 Direct testimonies of Mr. John Goodin and Mr. Neil Millar , who appear on behalf of the California Independent System Operator Corporation (CAISO).

Q.4. PLEASE IDENTIFY THE STATEMENTS WITHIN MR . GOODIN'S TESTIMONY TO WHICH YOU OBJECT?

A.4. My objection centers on the following section of his testimony:

> If load modifying demand response is consistently showing up at the right times and in right places to reduce peak demand and lower ramping needs, then yes, load modifying demand response can help load serving entities avoid procuring resource adequacy capacity. If, however, load

modifying demand response does not occur coincident with system needs, and does not help reduce peak demands or ramps, then it has less or even no resource adequacy benefit. For example, if load modifying demand response is not available during the system peak then the ISO must directly dispatch other resources to meet the system's coincident peak demand. In this case, the load modifying demand response would not have effectively reduced resource adequacy needs because it did not reduce the dispatch of other resources at the same time the system reached its highest coincident peak demand. (Goodin Direct, pp. 6- 7).

Similar statements appear on pp. 9-10 of Mr. Goodin's testimony.

Q.5. WHAT IS THE BASIS OF YOUR OBJECTION?

A.5. These statements fail to acknowledge that Load Modifying Resource DR may have a resource adequacy benefit even if the resource is not dispatched at the system peak hour.

If a resource is considered to be sufficiently reliable and readily available to be deployed during a system peak, then it has a resource adequacy benefit, regardless of whether it is in fact deployed during the peak hour. A similar case in point is a working combustion turbine that the CASIO would count toward resource adequacy even thou gh the generating unit had not actually been dispatched by the CAISO during the system peak hour.

The same reasoning applies to a Supply Resource DR (e.g., Proxy Demand Resource) that is not dispatched by the CAISO during the system peak hour. In this situation, the Supply Resource DR would fail the criterion set by Mr. Goodin for granting DR resource adequacy credit through no fault of its own, only because the market cleared at a price below the Supply Resource DR offer price in the CAISO energy market. Mr. Goodin's criterion requires the DR to "reduce the dispatch of other resources at the same time the system reached its highest coincident peak demand." (Goodin Direct, pp. 7 of 13.) But, if the Supply Resource DR was not dispatched, it would have no effect on the dispatch of other resources. Nonetheless, Mr. Goodin's testimony argues that Supply

Resource DR should be awarded credit toward meeting resource adequacy requirements, which is inconsistent with the standard he applies to Load Modifying Resource DR.

For the combustion turbine example, Supply Resource DR, and Load Modifying Resource DR, it is the availability and reliability of the resource that matters – not whether it is actually dispatched or affects the dispatch of other resources during a peak hour.

Q.6. IF THE IMPACT OF THE LOAD MODIFYING RESOURCE DR FAILS TO "SHOW UP" AS A REDUCTION IN PEAK DEMAND BECAUSE IT IS NOT DEPLOYED AT THE EXACT TIME OF THE MARKET'S PEAK, HOW CAN THE VALUE OF THIS RESOURCE BE RECOGNIZED FOR PLANNING PURPOSES?

A.6. I agree with Mr. Goodin that Load Modifying Resource DR may not be used to satisfy a load-serving entity's (LSE's) resource adequacy requirement under possible future RA rules, but should instead be regarded as a means to reduce a resource adequacy need (Goodin Direct, p. 5). This topic is discussed in my Opening Testimony (p. C-8, line 18 through p. C-9, line 21) in this proceeding. Also, please refer to Opening Testimony of Mr. Luke Tougas (p. 2-1, line 15 through p. 2-2, line 2). Recognition of the value of Load Modifying Resource DR in resource planning may be achieved by adjusting long-term load forecasts, including planning reserve margins, for the effect of Load Modifying Resource DR on the LSE's load forecast.

If all Load Modifying Resource DR is deployed during peaks in prior years, then this should not be an issue. This DR has indeed altered the demand which the market must serve and this will be recognized in load forecasts relying upon historical data reflecting the DR's impacts. I am assuming here that the level of demand reduction from the DR is stable – otherwise, adjustments may be necessary to recognize the growth or contraction in the amount of DR.

If *none* of the Load Modifying Resource DR has been deployed during peak hours in recent years, then the impact of this DR on peak needs is not reflected in the historical peak load data which the CAISO relies upon to develop long-term load forecasts. Yet, this DR resource nonetheless has value and should be recognized in resource planning. Provided this DR resource is reliable, then its projected level of potential demand reduction should be subtracted from the load forecast to arrive at a projection of firm load, and resource plans should be developed to satisfy the level of firm load.

In situations where some of the DR has historically been deployed during peaks and other DR has not, then the degree to which the impacts of DR are reflected in historical load data must be considered.

Q.7. HOW DOES THE ELECTRIC RELIABILITY COUNCIL OF TEXAS (ERCOT) MARKET TREAT LOAD MODIFYING RESOURCE DR IN ITS RESOURCE PLANS?

A.7. Prior to restructuring, ERCOT reduced its long term load forecasts to recognize that large industrial energy consumers served under interruptible tariffs were not "firm loads." There was no obligation to serve such facilities during a peak. In some cases, the entire interruptible load of the consumer was removed. In other cases (e.g., situations where the consumer's purchases from the grid were curtailed following some notice period), a portion of the consumer's projected load was removed from the long-term forecast to derive firm load.

In recent years, ERCOT has made adjustments to its load forecast to reflect utility-sponsored Load Management Standard Offer Programs. These Load Modifying Resource DR programs are given full-credit. That is, the total estimated demand reduction that could be achieved through these programs is subtracted from ERCOT's load forecast. ERCOT mon itors when these utility programs are deployed and has latitude to adjust how much credit these programs are given so as to avoid any "double -counting" wherein deployments coincident with system peaks might have already been recognized in the load forecast.

Q.8. MR. GOODIN STATES ON PAGE 7 OF HIS DIRECT TESTIMONY THAT THE FEATURE THAT DISTINGUISHES SUPPLY RESOURCE DR FROM LOAD MODIFYING RESOURCE DR IS THE SUPPLY RESOURCE DR'S ABILITY "TO REMOVE A SPECIFIED AMOUNT OF ENERGY FROM THE ELECTRIC GRID AT A GIVEN TIME AND PLACE IN ORDER TO SERVE THE POWER FLOW NEEDS OF THE ELECTRIC GRID." PLEASE COMMENT ON THAT STATEMENT.

A.8. I do not view Mr. Goodin's statement as necessarily true. A well-designed event-driven DR program operated outside of an ISO market can achieve this same goal. The ability of a DR program to achieve demand reduction depends more on the design of the program and the attributes of the participating loads than whether the program is classified as a Load Modifying Resource DR or a Supply Resource DR.

Q.9. PLEASE IDENTIFY THE STATEMENTS WITHIN MR. MILLAR'S TESTIMONY TO WHICH YOU OBJECT?

A.9. In his description of the benefits of CAISO's economic dispatch process relative to manual notification processes, Mr. Millar argues that grid operators must have control of DR resources through the CAISO's economic dispatch system in order to ensure prices are properly set. Mr. Millar purports (p. 8) that an advantage of CAISO's economic dispatch is:

> Price discovery – the price impacts of the DR resources can only properly be represented through market participation and directly contributing to price formation.

Q.10. PLEASE DESCRIBE YOUR CONCERN WITH THIS STATEMENT IN MR. MILLAR'S TESTIMONY.

A.10. As discussed in my Opening Testimony, Load Modifying Resource DR can affect prices in a similar manner to Supply Resource DR. The examples in my Opening Testimony demonstrate that a shift in a demand curve can have the same impact on wholesale market prices as a shift in a supply curve for the same quantity of DR. Inclusion in the CAISO's economic dispatch is not necessary for DR to contribute to price formation.

While there may be some infrequent situations where direct participation in the CAISO's economic dispatch will yield a mo re-accurate price (e.g., where the DR becomes the "marginal resource" and thus directly affects the market price, or in situations where the sponsor of a Load Modifying Resource DR program inaccurately forecasts market prices), the benefits of achieving better price information in such situations must be weighed against the costs of converting Load Modifying Resource DR programs to Supply Resource DR.

Q.11. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A.11. Yes.