Pacific Gas and
Electric Company ™

Mary A. Gandesbery

Mailing Address
P.O. Box 7442
San Francisco, CA 94120

Street/Courier Address
Law Department
77 Beale Street
San Francisco, CA 94105

(415) 973-0675
Fax: (415) 972-5952
Internet: MAGq@pge.com

January 31, 2011

Ms. Julie Fitch
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: A.08-06-001 Report on the Transition of Pacific Gas and Electric Company (U 39 E) Demand Response Programs into Market Redesign & Technology Update (MRTU)

Dear Ms. Fitch:

In accordance with Decision 09-08-027, Ordering Paragraph 24(b), attached please find Pacific Gas and Electric Company's report on the transition of demand response programs into Market Redesign and Technology Upgrade. This report is also being served on the most recent service list in Application 08-06-001 et. al. The report will also be available at this publicly available website:

http://apps.pge.com/regulation/search.aspx?CaseID=821

The case is "Demand Response 2009-2011 Projects"; the document type is "All"; the party is "PGE"; and the date fields are "1/31/11".

Very truly yours,

/s/
Mary A. Gandesbery
MAG/mw
Report
cc: Jessica Hecht, Administrative Law Judge,
Scarlett Lian-Uejio,
Natalie Walsh,
Ken Abreu,
Nick Ho,
Eileen Cotroneo,
Fadia Khoury,
Bruce Kaneshiro,
Robert Benjamin,
Mark Huffman,
Ulric Kwan,
Josephine Wu,
Sidney Dietz,
Steve Patrick
All parties of record in A.08-06-001 via email

Pacific Gas and Electric Company

Report on Integrating Demand Response Programs Into CAISO Wholesale Electricity Markets

January 31, 2011

In compliance with the California Public Utilities Commission (Commission) Decision 09-08-027 for PG&E's 2009-2011 Demand Response Application A.08-06-003 (DR Application Decision), Pacific Gas and Electric Company (PG&E) files this report to address Ordering Paragraph 24.b (OP24b). OP24b ordered PG&E to:

> *"[File a] report on the transition of demand response programs into Market Redesign and Technology Upgrade. This report shall include lessons learned from the utilities' 2009 pilots and their 2010 Proxy Demand Resource experience, including performance assessments as well as an evaluation of expected costs and benefits of integrating of all programs into Proxy Demand Resource (if such programs have not already been integrated) and Participating Load (for all programs). Each of the utilities shall provide this report by January 31, 2011."*[1]

The guidance provided by the Commission for the 2012-2014 Demand Response Applications, clarified the intent of OP24b and directed PG&E to provide:

> *"1) an evaluation of the costs and benefits of integrating all demand response programs into Proxy Demand Resource and/or Participating Load systems developed by CAISO, 2) an assessment of the effect of each demand response program on scarcity pricing, 3) the identification of any barriers to integration with Proxy Demand Response and Participating Load, and 4) suggested next steps on how to address those barriers."*[2]

Lessons Learned From PG&E's 2009 Participating Load Pilot

PG&E filed a report on December 31, 2009 summarizing its findings regarding its 2009 Participating Load (PL) Pilot[3]. The PL Pilot successfully integrated into the California Independent System Operator (CAISO)

[1] Decision 09-08-027, *Decision Adopting Demand Response Activities And Budgets For 2009 Through 2011*, August 20, 2009, p. 240

[2] *Administrative Law Judge's Ruling Providing Guidance For The 2012-2014 Demand Response Applications*, August 27, 2010, p. 11.

[3] 2009 Pacific Gas and Electric Company Participating Load Pilot Evaluation, December 31, 2009

non-spinning reserve market, receiving market awards and dispatches from the CAISO, and responding appropriately to these CAISO dispatches in the timeframe required. The PL Pilot allowed both the CAISO and PG&E to explore the limitations of the existing systems and develop solutions to mitigate some of these limitations.

The 2009 PL Pilot has given PG&E a better understanding of integration issues that must be addressed to further advance DR in the wholesale market. PG&E learned that it is technically feasible to offer ancillary services (A/S) to the CAISO, but requires extensive system modifications and new developments to meet the core requirements.

The test participants enrolled in this pilot have had extensive knowledge and relevant history regarding DR. They also have made a significant investment in sophisticated equipment and EMS systems, which have made them ideal candidates for this challenging product. However, it does not translate that each potential participant will have the same ease of performance if enrolled.

Lessons Learned From PG&E's 2010 Proxy Demand Resource Experience

PG&E was unable to bid into the CAISO market in 2010 with the Proxy Demand Resource (PDR) market mechanism. Due to delays with the approval of the CAISO's tariff modifications at the Federal Energy Regulatory Commission (FERC) to allow the PDR mechanism into the CAISO markets and the subsequent lack of approval from the Commission to allow PG&E to utilize PDR resources for bidding, PG&E was not able to garner any experiences with bidding in PDR resources.

However, PG&E did gain some experience that will be useful for managing PDR in the future. PG&E was able to:

- Register two PDR resources with the CAISO;
- Enroll 21 customers in these resources;
- Integrate some of PG&E's DR systems with some of PG&E's Energy Procurement systems; and
- Participated in many CAISO market simulation events to enable the CAISO to validate its PDR deployment and ensure that PG&E's systems were compliant with the CAISO's PDR systems.

The Commission approved PG&E's request to be able to bid into the market in Decision 10-12-036[4], pending the approval of its Advice 3689-E-A. Assuming the Commission approves Advice 3689-E-A, PG&E will begin bidding PDR resources into the CAISO markets in June 2011 and gain additional experience with PDR.

[4] Decision 10-12-036, *Decision Regarding Phase Four Direct Participation: Authorization For Investor-Owned Utilities To Participate In Bidding Of The CAISO's Proxy Demand Resource Product*, December 16, 2010, p. 7-8.

An Evaluation Of The Costs And Benefits Of Integrating All Demand Response Programs Into Proxy Demand Resource And/Or Participating Load Systems Developed By The California Independent System Operator

The CAISO has developed three mechanisms to integrate demand response into its markets: Proxy Demand Resource (PDR), Participating Load (PL), and the Reliability Demand Response Product (RDRP)[5]. The CAISO plans to implement the RDRP in summer 2012[6]. Each of these mechanisms allows the Investor Owned Utilities (IOUs) or an independent third party to bid demand response into the CAISO markets.

PG&E currently has 10 Demand Response programs, including the dynamic rate programs:

1. Base Interruptible Program (BIP)
2. SmartAC
3. Capacity Bidding Program (CBP)
4. Demand Bidding Program (DBP)
5. PeakChoice™
6. Dynamic Rates (Peak Day Pricing (PDP) and SmartRate)
7. Time-Of-Use Rates (TOU)
8. Aggregator Managed Portfolio (AMP)
9. Optional Binding Mandatory Curtailment Program (OBMC)
10. Scheduled Load Reduction Program (SLRP)

In its 2012-2014 Demand Response Application, PG&E will request to incorporate DBP into the PeakChoice™ program as the simplest, lowest cost option to allow DBP participants to participate in the CAISO markets. The ideal CAISO mechanism for each of these programs is different. Ideally, PG&E would migrate the programs to the following CAISO mechanism:

1. PDR: CBP, SmartAC, PeakChoice™, AMP, and PDP
2. PL: None planned at this time

---

[5] *Decision on Reliability Demand Response Product*, CAISO Board Of Governors, November 1-2, 2010, Motion Number 2010-11-G3.

[6] Reliability Demand Response Product, Revised Draft Final Proposal Version 2.0, p. 4.

3. RDRP: BIP
4. No Mechanism: TOU, OBMC, and SLRP

In general, the PDR mechanism is a lower cost option to integrate PG&E's existing DR resources compared to the PL mechanism due to reduced operating costs and requirements for PDR compared to PL. The RDRP mechanism builds on the PDR foundation and is designed to integrate emergency-triggered Demand Response programs that cannot be integrated through the PDR and PL mechanisms.

The rationale for this grouping is due to the various Demand Response filings made in the past two years. In the DR Application Decision, the Commission ordered PG&E to file a plan to convert at least ten percent of its Demand Response MWs to be PDR compatible[7]. In compliance with this order, PG&E filed Advice Letter 3635-E, where PG&E outlined that it planned to integrate the PeakChoice™ program in 2010, CBP in 2011, and SmartAC in 2012 with the CAISO markets through the PDR mechanism. This Advice Letter was superseded by Advice Letter 3635-E-A to reflect a one year delay in this plan due to the lack of direct participation in 2010. Further changes may be proposed in PG&E's Demand Response 2012-2014 Application (2012-2014 Application) to be filed on March 1, 2011.

The PDR mechanism is also planned as the market mechanism to integrate any new AMP contracts with the CAISO markets. However, existing contracts are not able to be bid as PDR and expire in 2011. The Commission has twice disallowed PG&E's request to hold a solicitation to replace expiring contracts with new PDR-compliant demand response contracts, which has created uncertainty about the amount of DR resources that PG&E will be able to bid into the market as PDR in the next few years.[8]

The PDR mechanism is also planned as the market mechanism for the PDP program to integrate with the CAISO markets. However, the PDP program is still being rolled out to customers and it is premature to bid the PDP program into the markets at this time.

The Commission adopted a settlement regarding emergency triggered Demand Response programs in Decision D.10-06-034[9]. As part of this settlement, the CAISO agreed to develop the RDRP mechanism and the IOUs agreed to convert all of their emergency triggered Demand Response programs and bid them into the CAISO market through the RDRP mechanism. For PG&E, the only emergency-triggered program to which this applies is BIP.

---

[7] Decision 09-08-027, *Decision Adopting Demand Response Activities And Budgets For 2009 Through 2011*, August 20, 2009, Ordering Paragraph 25, p. 240-241

[8] *Decision Granting In Part The Petition Of Pacific Gas and Electric Company to Modify Decision 09-08-027*, D.10-12-033, Ordering Para. 5; *Decision Adopting Demand Response Activities and Budgets for 2009 Through 2011*, D. 09-08-027, Ordering Para. 19.

[9] *Decision Adopting Settlement Agreement On Phase 3 Issues Pertaining To Emergency Triggered Demand Response Programs*, D.10-06-034, June 24, 2010.

In the 2012-2014 Application, PG&E will propose a timeline to transition PG&E's programs into the relevant CAISO market mechanism in accordance with our responses to Ordering Paragraph 25.

Programs That Will Not Be Integrated Into The CAISO Markets

Time-Of-Use Rates

TOU rates cannot be integrated into the CAISO market through the PDR, PL, or RDRP mechanisms as it is not a "dispatchable" DR program. The changes to consumer behavior are reflected in the load forecast that PG&E submits to the CAISO on a daily basis.

Optional Binding Mandatory Curtailment Program

The OBMC program cannot be integrated into the CAISO market through the PDR, PL, or RDRP mechanisms. The RDRP trigger occurs before a Stage 1 emergency and the OBMC program trigger is during a Stage 3 emergency. Given the size of the program (less than 10 Megawatts (MW)), number of customers (31), and the fact that PG&E does not count any of the OBMC MW for Resource Adequacy (RA), PG&E does not believe that it is worthwhile to consider modifying the program or creating a market mechanism at the CAISO to integrate this program.

Scheduled Load Reduction Program

The SLRP does not currently have any enrolled customers. Thus, PG&E does not believe that it is worthwhile to consider modifying the program or creating a market mechanism at the CAISO to integrate this program.

Costs Of Integrating Demand Response Programs

The costs presented here for the conversion of existing Demand Response programs to be compatible with the PDR and RDRP mechanism are different than what will be presented in the 2012-2014 Application. This is due to the difference in assumptions made in the 2012-2014 Application and this response, including the programs that will be converted and the timeline over which the conversion will occur. The costs provided here assume a specific set of implementation decisions and timelines are followed for converting Demand Response programs to be PDR compatible and cannot be used to determine the price of any individual component in exclusion to the other components and timelines given. Also, these costs do not include other costs such as the need for better forecasting tools or a centralized enrollment system. The 2012-2014 Application will propose a different set of programs to be converted with a different timeframe of that conversion that aligns with PG&E's current vision of integrating its Demand Response programs into the CAISO market at the least cost to ratepayers. The 2012-2014 Application will also ask for funding for some foundational IT systems that will reduce the long term costs of operating the Demand Response programs. Thus, the costs presented here cannot be compared to the 2012-2014 Application.

Common Costs

There are several common tasks that need to be performed to integrate any Demand Response program into the CAISO market. These include:

- Registering the Demand Response program participants with the CAISO in a specific resource that maximizes the value of the potential demand response for ratepayers;
- Create an accurate interval-by-interval (5 minute or hourly) forecast of the underlying load and the curtailment possible for each interval on a daily and hourly basis;
- Bid the Demand Response resource into the CAISO market;
- Submit meter data to the CAISO on a continuous daily basis at the interval size required (5 minutes or hourly);
- Receive and process market awards and dispatches from the CAISO;
- Automate the method to issue notifications and dispatches to Demand Response participants that were called by the CAISO. These notifications and dispatches must be on a locational basis; and
- Settle with the CAISO based on the actual performance of the Demand Response resource.

Most of the Information technology (IT) infrastructure and operational processes and procedures have been implemented to meet these requirements for bundled customers that are enrolled in the PeakChoice™ program for participating in the Day-Ahead Energy market of the CAISO. Recovery for the costs of this implementation will be filed in the Market Redesign and Technology Upgrade Memorandum Account (MRTU Memo Account).

On the wholesale side, there are still costs to implement the requirements to participate in the Real-Time market of the CAISO and the Ancillary Services markets of the CAISO for PG&E's internal programs. In addition to the costs to participate in the Real-Time and Ancillary Services markets of the CAISO, PG&E is awaiting the outcome of the Demand Response OIR Phase 4 Part 2 on Direct Participation to estimate, design, and implement the capabilities to allow non-PG&E Demand Response Providers to participate in the market with PG&E's bundled customers as well as to allow PG&E to utilize its Direct Access participants in the CAISO markets. Costs for enabling direct participation from third-party DR providers and for allowing Direct Access customers participating in PG&E's DR programs are not included in this estimate.

On the retail side, the method of automated notification and dispatches on a locational basis must be managed on a program-by-program basis as the means to notify and dispatch Demand Response program participants on a locational basis differs by the tariff.

Schedule Used To Estimate The Costs To Bid PG&E Demand Response Programs Into The CAISO Markets

For the specific implementation plan given below, the incremental costs beyond the costs already spent to enable the PeakChoice™ program's bundled customers to directly participate in the CAISO day-ahead energy market are provided. PG&E has assumed a strict sequence of actions in estimating the costs to implement direct participation based on the best available data at this time. The estimated costs for a program cannot be viewed in isolation, due to costs associated with scaling and common platforms made in earlier implementations reduces subsequent program costs.

Name/Short Description	Cost Estimate	Cumulative Cost Estimate
Convert DBP for Day Ahead Energy	$5,050,000	$5,050,000
Convert CBP for Day Ahead Energy	$820,000	$5,870,000
Convert SmartAC for Day Ahead Energy	$7,210,000	$13,080,000
Convert PDP for Day Ahead Energy	$3,890,000	$16,970,000
RDRP Foundation (BIP)	$4,000,000	$20,970,000
PDR – Real Time Foundation (PeakChoice)	$1,260,000	$22,230,000
CBP for Real Time Energy	$420,000	$22,650,000
SmartAC for Real Time Energy	$795,000	$23,445,000
PDR – A/S Foundation (PeakChoice, excludes Telemetry)	$2,420,000	$25,865,000

Table 1: Estimated costs to implement direct participation for PG&E's programs (all costs are in 2010 dollars and exclude operation and maintenance costs related to system upkeep)

The costs for Direct Participation where the Demand Response Provider is not the same as the Load Serving entity can only be estimated after the Commission has decided the policy and implementation issues regarding Direct Participation. This is currently being considered in the DR OIR R.07-01-041 Phase 4 Part 2 proceeding. Therefore, the costs for Direct Participation are not included above.

PeakChoice™

PeakChoice™ and its underlying IT systems have been integrated with the CAISO's PDR mechanism for the day-ahead energy market for bundled customers. These costs will be accounted for in the PG&E MRTU Memorandum Account. To utilize PeakChoice™ participants in the real-time and ancillary services markets, additional costs will need to be incurred.

Demand Bidding Program

PG&E plans to incorporate DBP into the PeakChoice™ program as the simplest, lowest cost option to allow DBP participants to provide value in the CAISO markets in the 2012-2014 Application. If the Commission does not allow this, the current estimated costs to allow the DBP to participate in the CAISO's PDR mechanism are $5,050,000.

This includes costs to automate the registration of hundreds of participants in PDR resources and assumes that the CAISO will support automated registrations, to the costs to convert the DBP IT systems to allow for locational bidding, and the costs to integrate the DBP IT systems into the existing communication IT infrastructure between Demand Response and Energy Procurement.

Capacity Bidding Program

PG&E had planned to integrate the CBP into the CAISO's PDR mechanism in 2011. However, PG&E was unable to bid into the CAISO markets in 2010 and thus was unable to test its systems and procedures to ensure complete functionality. Due to this inability to bid in 2010, PG&E plans to bid into the CAISO market with the PeakChoice™ program participants in 2011. After ensuring the integrity of its systems and procedures in 2011, PG&E will transition the CBP to PDR in 2012.

For the CBP to be compatible with PDR, two IT systems are required to change: the APX CBP platform used by all of the IOUs for the CBP and PG&E's internal systems.

The APX CBP platform required two main changes: an adjustment of when the aggregators could nominate customers and the ability to nominate customers to portfolios by SubLAP.

The adjustment for when an aggregator could nominate customers will be changed from the initial 5 days before the beginning of the month to 15 days before the beginning of the month. This change is required to allow PG&E to register the updated nominations with the CAISO, pass through the review process of the CAISO, and have a usable Demand Response resource for the month.

The ability to nominate customers to portfolios by SubLAP is required to meet the CAISO PDR requirement of locational dispatch at levels no larger than a SubLAP.

PG&E's IT systems will require enhancements to manage portfolio based nominations that are required by CBP compared to individual customers that are allowed under PeakChoice™. PG&E will also need to be able to interface with the APX CBP system and provide an automatic (i.e. no human interaction) dispatch from PG&E when it receives a market award. Lastly, PG&E will integrate CBP IT systems into the existing communication IT infrastructure between Demand Response and Energy Procurement.

The costs to allow the CBP to participate in the CAISO's PDR mechanism are strongly dependent on the costs outlined above to allow the DBP to participate as part of a PDR resource. Assuming that the DBP can be used for PDR bidding, the incremental costs over and above the costs to handle the CBP is currently estimated as $820,000.

SmartAC

PG&E planned to integrate the SmartAC program into the CAISO's PDR mechanism in 2012. However, given the inability to bid into the CAISO market through the PDR mechanism in 2010 and the subsequent delays in PeakChoice and the CBP, PG&E now plans to integrate the SmartAC program into the CAISO's PDR mechanism in 2013 for participation in the day-ahead energy market

To integrate SmartAC with PDR, PG&E will need to manage the enrollments from the SmartAC system with registrations at the CAISO for hundreds of thousands of participants. PG&E will be required to dispatch the SmartAC participants by SubLAP and thus will need to develop a system to map customers to SubLAPs. PG&E will also need to integrate the dispatch system of SmartAC with any market award and dispatch from the CAISO.

The incremental cost for integrating SmartAC is estimated to be $6,760,000. This cost estimate includes the costs to scale the IT systems to handle the hundreds of thousands of SmartAC participants, for mapping all customers to the relevant CAISO Pricing node to allow for true locational dispatch in the CAISO market, and to integrate the existing SmartAC platform (Yukon) with PG&E's PDR IT systems.

Base Interruptible Program

PG&E participated in a settlement with other stakeholders, including the CAISO, to limit the amount of emergency triggered Demand Response that could count for Resource Adequacy purposes. This settlement was approved by the Commission in Decision D.10-06-034 (BIP Settlement). Part of the BIP Settlement was that the CAISO would develop a new product in its markets, the Reliability Demand Response Product (RDRP), and that all solely emergency triggered programs would need to be bid into the RDRP. For PG&E, this is the BIP.

The RDRP is very similar to the PDR product of the CAISO, with some added features to enhance compatibility with the existing emergency triggered Demand Response programs of the IOUs and some enhancements to increase the visibility of RDRP resources to the CAISO.

Thus, the requirements for the BIP to be compatible with the RDRP are very similar to other programs to be compatible with PDR. The work required for compatibility includes, but is not limited to, the following:

- Providing enhancements to PG&E's Energy Procurement IT systems to manage the continual bidding requirements mandated by the RDRP;
- Integration of the BIP notification and registration systems with the existing PDR infrastructure to ensure consistency and response to CAISO notifications;

PG&E has estimated the incremental cost of this work to be $4,000,000.

Peak Day Pricing

PG&E current direction from the Commission is to default all Commercial and Industrial customers to PDP in 2011 and possibly transitioning all residential customers to PDP in the 2013-2014 timeframe. PG&E does not propose to integrate the PDP into the CAISO's PDR mechanism at this time. The central issue with integrating PDP participants into the CAISO's PDR mechanism is that the marketing to customers who transitioned to PDP did not incorporate the idea of a possible PDP event due to market prices, nor was PDP envisioned as a locational program. Instead, the PDP was viewed as a default, system-wide program.

As experience is developed with PDP and customers become acclimated to the program, PG&E will review transitioning the program to be compatible with the CAISO's PDR mechanism.

If PG&E was to convert PDP to be compatible with the CAISO's PDR mechanism, and the SmartAC program was already bidding as PDR resources, the current estimated incremental cost for doing this change would be $4,000,000. This is for IT infrastructure only and does not include any funding for the customer communications needed for this change.

Real-Time Energy and Ancillary Services Market Bidding

PG&E does not have sufficient experience with the PDR market mechanism of the CAISO at this time to plan with a high degree of certainty the full bidding in real time and A/S markets. Through the 2012-2014 timeframe, PG&E will be developing the experience with PDR and additional experience in the Ancillary Service markets through pilots. Thus, real time and Ancillary Service market participation in this specific implementation plan occurs after the implementation of all day-ahead market direct participation and also after the implementation of RDRP.

The current incremental cost estimates for the higher level of automation required to participate in the CAISO's real time energy markets are provided below, assuming that RDRP has been implemented.

- For PeakChoice: $1,260,000;
- For CBP: $420,000; and
- For SmartAC: $795,000.

The current incremental cost estimates for the higher level of automation for Ancillary Services are $2,420,000, assuming that RDRP was implemented and that the implementation to allow the PeakChoice™ program to participate in the real-time energy market had occurred. This does not include an estimated $2,800,000 for the IT systems required to handle the telemetry, the costs to purchase the meters needed to meet the requirements for Ancillary Services, or the operating costs of the telemetry-quality meters.

Aggregator Managed Portfolio

The AMP contracts are bilateral contracts that will expire at the end of 2011. These contracts do not contain any language that requires the ability of the aggregators to notify and dispatch their enrolled participants by location, which is required by the CAISO PDR mechanism. PG&E plans to seek an extension of the existing AMP contracts through 2012 in the 2012-2014 Application, and also ask for the ability to issue a new round of Request For Proposals (RFPs) to the aggregators and that will require the ability to integrate with the CAISO markets through the PDR mechanism. PG&E is unable to estimate the potential cost for this additional functionality that will be included in the contracts and must wait for the aggregators to make competitive bids.

Benefits Of Integrating Demand Response Programs

There are several benefits that are possible by integrating demand response resources into the CAISO markets:

- Decrease in the wholesale market prices;
- Decrease in the ability of supply side resources to exercise market power;
- Increased transparency to the CAISO of resources available at any time;
- Integration of variable intermittent renewable resources;
- Mitigation or avoidance of Scarcity Pricing events;
- Avoided cost of procuring resources to provide energy or ancillary services to the CAISO;
- Avoidance of Greenhouse Gases and other environmental impacts produced by fossil fuel based supply side resources; and
- Improved reliability.

It is very difficult to quantify the exact value from each benefit, as any calculation would involve sizable assumptions on the markets, participants, and likely future events. The Commission acknowledges these difficulties in its attachment to the proposed decision in the Demand Response OIR Phase 1 proceeding on cost-effectiveness of Demand Response resources.[10] PG&E does not believe that it has sufficient experience with the CAISO markets and the ability to forecast the effects of the impending changes at the CAISO to provide a quantitative analysis at this time. Some of the major initiatives that could have significant effects on the CAISO markets include the Renewable Integration initiative and the Convergence Bidding Initiative.

Assessment Of The Effect Of Each Demand Response Program On Scarcity Pricing

Scarcity Pricing in the CAISO markets is an administratively set price when the amount of ancillary services (A/S) that can be procured by the CAISO through its normal market mechanisms drops below certain minimums. Scarcity Pricing increases the price that the CAISO will purchase A/S dramatically, incenting additional resources to provide A/S. Scarcity Pricing events can occur in both the Day-Ahead market and in the Real-Time market.

Demand Response resources that participate in the CAISO markets can have an effect on Scarcity Pricing in two ways: (1) provide additional A/S resources into the CAISO A/S markets and directly relieve Scarcity Pricing or (2) provide additional energy in the CAISO energy markets, freeing up other resources that would have been providing energy to instead provide A/S, indirectly relieving Scarcity Pricing.

In compliance with OP26 of the DR Application Decision, PG&E filed Advice Letter 3719-E, stating that that PG&E would evaluate offering an A/S option in its PeakChoice™ program, its CBP program, its Smart

[10] Decision 10-12-024, Decision Adopting A Method For Estimating The Cost-Effectiveness Of Demand Response Activities, Attachment 1, December 21, 2010, p.14, 16, 17, 31, 32, 34, 35

AC program, or its AMP contracts and will make its proposals regarding the A/S option in its 2012-2014 Demand Response Application. In the 2012-2014 Application, PG&E will recommend adding an option to the PeakChoice program to have a ten (10) minute full response option. To the extent that PG&E offers Demand Response A/S capable resources into the CAISO market, these resources would increase the supply of A/S and could reduce the frequency of a Scarcity Pricing event.

For a Demand Response resource that is incapable of providing A/S to affect Scarcity Pricing indirectly, it must be capable of participating in the same market that has the Scarcity Pricing event. Thus, a Demand Response resource that can bid into the Day-Ahead market can indirectly affect a Scarcity Pricing event, by avoiding a Scarcity Pricing event altogether or reducing the duration of a Scarcity Pricing event by providing energy and allowing other resources to offer A/S. A Demand Response resource that can bid into the Real-Time market can indirectly affect a Scarcity Pricing event in the Real-Time market, by avoiding a Scarcity Pricing event altogether or reducing the duration of a Scarcity Pricing event by providing energy and allowing other resources to offer A/S.

The Identification Of Any Barriers To Integration With Proxy Demand Response And Participating Load

The PDR, RDRP, and PL mechanisms of the CAISO have new requirements for Demand Response programs. In addition, the integration with the CAISO wholesale markets introduces additional challenges. Specifically, these are:

- Size Requiring Telemetry – The CAISO tariff requires that any resource larger than ten (10) MW must provide telemetry. This adds additional cost on to any Demand Response program that integrates into the CAISO markets;

- The continuous metering requirements – Demand Response Providers (DRPs) are required to submit daily interval meter reads from their Demand Response participants to the CAISO for calculating settlements and performance. This data must be submitted at the correct interval granularity, either 5-minute data or hourly data. This is significantly higher than the monthly analysis that is currently required for the incentive and performance settlement with retail customers. This is a costly requirement to DR;

- The cost of real-time telemetry – Some markets of the CAISO, such as A/S, require real-time telemetry, i.e. a meter read no older than 1 minute submitted every 4 seconds to the CAISO control center. The cost for real-time telemetry is currently very high. Such requirements may not be necessary.

- Dispatch notification times – Some markets of the CAISO, such as the Real-Time market and the A/S markets, have extremely short response times, i.e. less than 10 minutes. To be able to bid and perform in such markets, automated notification and response of Demand Response participants is required. Automated notification and response can be costly to provide;

- Lack of rules and regulations for handling Direct Access (DA) and Community Choice Aggregation (CCA) Demand Response participants – In Phase 4 Part 2 of the Demand Response OIR, discussions on what the roles, responsibilities, and financial settlements between the IOUs and Energy Service Providers (ESPs), non Investor Owned Utility (non-IOU) DRPs, and the customer are occurring. Until these issues are resolved, non-IOU DRPs are prohibited from using IOU bundled customers as Demand Response in the CAISO market. This also prohibits the IOUs from bidding the Demand Response of Direct Access customers enrolled in the Demand Response tariffs of the IOUs into the CAISO wholesale markets;

- Increased perception of risk by Demand Response participants from incorporating retail Demand Response programs into the wholesale market, both in number of times called and when the calls are made – Typically, existing and potential Demand Response participants incorrectly assume that there is a substantially increased risk of being called when Demand Response is explicitly bid into the CAISO markets. This could potentially decrease the amount of Demand Response in the existing IOU Demand Response programs, limit the growth of these same programs, or require higher incentive levels;

- Financial risk from participating directly in the wholesale market – Participating directly in the CAISO markets with Demand Response will result in financial debits and credits as Demand Response participants perform or fail to perform as forecast. This increases the reporting and scheduling requirements for both PG&E's Demand Response department and its merchant office;

- Existing programs – In general, existing PG&E Demand Response programs were not designed with integration of the CAISO wholesale market in mind, thus notification times, triggers, and compensation for demand response are not necessarily in line with the CAISO markets; and

- Allowing Demand Response resources to participate in the spinning, regulation up, and regulation down markets of the CAISO – the CAISO is unable to utilize Demand Response resources in its spinning, regulation up, and regulation down markets due to regulatory barriers at the Western Electric Coordinating Council (WECC). The WECC rules specifically require generation resources to provide these services to the CAISO and do not allow for any other type of resource to provide these services.

Suggested Next Steps On How To Address Those Barriers

The barriers listed in the previous section can be overcome in a variety of manners. Specifically, PG&E proposes the following as the preferred option:

- Size Requiring Telemetry – The size should be raised by the CAISO to a more reasonable level for Demand Response resources. PG&E believes that a level of 50 to 100 MW would be reasonable;

- The continuous metering requirements – PG&E has developed the Information Technology (IT) infrastructure to be able to handle the continuous metering requirements of the CAISO for its existing Demand Response programs on a limited scale and will request funding to do so on a larger scale in the 2012-2014 Application.

- The cost of real-time telemetry – Sampling or other statistical techniques could be authorized by the CAISO/WECC which would lower overall costs to provide telemetry. PG&E requires the Commission to issue a decision on who should incur the costs for real-time telemetry to the CAISO for those resources that provide A/S. Some foundational investments to drive down the cost curve of this technology class could dramatically decrease the cost of providing telemetry to customers;

- Dispatch notification times – The increased promotion of Automated Demand Response via OpenADR and Smart Energy Protocol 2.0 to customers will dramatically reduce response times for Demand Response participants, allowing these participants' Demand Response capabilities to be used in the A/S and real-time markets;

- The lack of rules and regulations for managing DA and CCA Demand Response participants – These rules and regulations DA and CCA Demand Response participants will be resolved in the Demand Response OIR Phase 4 Part 2;

- Increased perception of risk by Demand Response participants from incorporating retail Demand Response programs into the wholesale market, both in number of times called and when the calls are made – PG&E will need to perform outreach and education to its existing and potential Demand Response population to ensure that the participants understand the risks involved, both the level and quantity;

- Financial risk from participating directly in the wholesale market – PG&E will need to develop better forecasting models and methodologies, as well as change its bidding and hedging strategies, to ensure that PG&E's ratepayers are protected;

- Existing rate schedules – PG&E will need to submit changes to the existing Demand Response programs to align them with the requirements of the CAISO, including the notification times, triggers, and possibly the compensation; and

- Allow DR as spinning reserves and regulation – the CAISO and the WECC will need to change their tariffs and regulations, respectively, to allow Demand Response resources to participate in the spinning, regulation up, and regulation down markets. This would align with existing Federal Energy Regulatory Commission orders to the WECC and CAISO as well as a recently-completed CAISO initiative to allow all resources to provide spinning reserves.