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Witness(es): Alex Papalexopoulos
Spence Gerber
Jay Zarnikau

PACIFIC GAS AND ELECTRIC COMPANY

2013 DEMAND RESPONSE RULEMAKING 13-09-011

PHASES 2 AND 3

APPENDICES

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APPENDIX A

DIRECT TESTIMONY OF ALEX PAPALEXOPOULOS

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

Q 1 Please state your name and business address.

A 1 My name is Alex Papalexopoulos. My business address is 268 Bush Street, Suite 3633, San Francisco, California.

Q 2 By whom are you employed and in what capacity?

A 2 I am the president, CEO and Founder of ECCO International. My firm provides consulting and software services worldwide to a wide range of clients such as Governments, Regulators, Utilities, Independent System Operators, Generators, Marketers, Traders and Software vendors. These services are in the areas of electric industry restructuring, public policy, market analysis and energy economics, energy market design and implementation, energy market simulations and system reliability studies, smart grid and renewable energy, power systems operations and real time control.

I am also the CEO and Chairman of the Board of ZOME Energy Networks, a start-up energy software company which specializes in the research, development and commercialization of demand response management technologies and their integration in the wholesale energy markets.

Q 3 Please summarize your educational and professional background.

A 3 I hold an Electrical and Mechanical Engineering Diploma from the National Technical University of Athens, Greece and M.S. and Ph.D. degrees in Electrical Engineering from the Georgia Institute of Technology, Atlanta, Georgia, both with emphasis on power and energy systems modeling. From 1985 till 1998 I was employed by Pacific Gas and Electric Company. At PG&E I was responsible for the development of methodologies, advanced models, software, large databases and information systems to support PG&E's Energy Management System, system operations, grid and merchant operations, transmission planning, transmission and power contracts and power generation. I also worked on the development of power system analytical methods and software in a number of other areas, including optimization, dynamic and voltage stability, internet/intranet applications for the QFs, bidding systems for resource acquisitions, and costing methodologies for transmission services . From 1994 till 1998 I was Director of the Electric Industry Restructuring Group where I was responsible for the development of the market architecture of the CAISO and the CA Power Exchange and the implementation of advanced methodologies and models, software and systems to support the new market structures in the emerging energy marketplace in California.

Since 1998 I have been President and CEO of ECCO International. In that capacity I have been involved in the design and implementation of several wholesale energy markets in North and South America, Western and Eastern Europe and Asia. Examples include the wholesale energy markets in California, Texas, ISO New England, Independent Electricity System Operator in Canada, Poland, Hungary, Greece, Japan and Argentina. I have been a key consultant to the CAISO since its inception in 1998 till 2006. I was the technical lead of the entire Market Redesign and Technical Upgrade (MRTU) project till 2006. As a market designer I have also designed several DR products for wholesale energy markets. Examples include the Price Sensitive Demand Response products on the supply side for the wholesale markets in Greece and Poland. Since 2009, I have been heavily involved in the restructuring of the Greek energy sector, including physical and virtual sales of assets of the dominant utility (Public Power Corporation), redesign of the wholesale energy market, etc., for the implementation of the reforms of the energy sector in Greece pursued by the European Union, the European Central Bank and the International Monetary Fund.

I have published numerous papers in refereed scientific journals and conferences and given numerous invited presentations in leading organization and academic institutions on issues related to energy market design, including DR technologies, algorithms, design and implementation. I have organized and trained various leading organizations in the area of energy market design and chaired numerous panels and special sessions in IEEE. I am the 1996 recipient of IEEE's First Prize Paper Award. I am also a Fellow of IEEE for original contributions in the field of power engineering.

Q 4 On whose behalf are you appearing in this proceeding?

A 4 I am appearing on behalf of Pacific Gas and Electric Company (PG&E).

Q 5 What is the purpose of your testimony?

A 5 The purposes of my testimony are to 1) explain why integration of Supply Resource DR Resources in the CAISO market poses several challenges whose resolution is costly and complex, 2) explain that Load Modifying Resource DR can contribute to price formation in the CAISO energy market, 3) explain how Load Modifying Resource DR currently impacts the CAISO markets, 4) propose changes to the CAISO processes to better coordinate Load Modifying Resource DR with the CAISO markets, 5) identify opportunities to reduce the cost and complexity of bidding Supply Resource DR into the CAISO market, 6) explain why the incremental benefits of dispatching DR in the CAISO market as supply relative to dispatching the same DR as load are very small, and 7) explain that a transition to large scale integration of DR into the CAISO market as supply will take a significant amount of time to be valuable.

My testimony is complementary to Mr. Zarnikau (Exhibit (PG&E-01), Appendix C) testimony, as his covers electric market structure in general in considering the CAISO market, as well as ERCOT as a specific example. My testimony focuses on the CAISO market in specific detail.

Q 6 What conclusions have you reached?

A 6 The following are my conclusions:

1) Participation of Supply Resource DR in the CAISO market poses several costly and complex challenges.
2) Load Modifying Resource DR directly contributes to the price formation in the CAISO energy market and helps reduce the CAISO energy market price.
3) Load Modifying Resource DR directly impacts the CAISO markets.
4) Changes can potentially be made to the CAISO processes to better coordinate Load Modifying Resource DR with the CAISO markets.
5) There are potentially ways to reduce the cost and complexity of bidding Supply Resource DR into the CAISO markets.
6) The incremental benefits of dispatching DR as supply relative to dispatching the same DR as load are very small in the CAISO markets.

7) A transition to large scale integration of DR into the CAISO market as supply will take significant amount of time to be valuable.

8) The CAISO market can work if DR resources are incorporated as Load Modifying Resource DR into the market.

9) 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.

10) Load Modifying Resource DR can be economically efficient in the CAISO markets.

Q 7 Will participation of supply resource DR in the CAISO market pose several challenges whose resolution is costly and complex?

A 7 Yes. According to D.14-03-026, Ordering Paragraph 3, Supply Resource DR is defined as resources that are integrated into the California Independent System Operator's energy markets. Thus, Supply Resource DR is optimized and dispatched alongside all conventional resources to support a security constrained economic dispatch and unit commitment solution. The security constrained unit commitment and economic dispatch processes are complex processes that take into account economic and technical information about the generation fleet and the transmission grid, including system, resource and transmission constraints. Resources that participate in the CAISO wholesale energy markets need to comply with complex market rules regarding eligibility, registration, bidding and scheduling, telemetry, metering, settlements, resource performance requirements, compliance obligations, etc. First and foremost, these market rules have been traditionally developed to deal with the operational characteristics of conventional generation resources.

This market architecture means that there are high transactions costs associated with DR programs being directly bid, scheduled and dispatched by the CAISO. Thus, participation of Supply Resource DR in this market architecture poses several challenges whose resolution is likely to be costly and complex. Further, it exposes DR resource owners to certain risks which require special attention for successful participation in the CAISO wholesale energy market. It requires substantial input and interaction with end-use customers, who may be unwilling to participate if the economic value and the price signals cannot support these transactions from the customer's viewpoint. Further it requires an in-depth understanding of the end-use composition of the customer's electricity demand and a baseline methodology which accurately measures the consumer's actual performance.

Consequently, bidding Supply Resource DR in an electricity market requires considerable foresight, sophistication, and knowledge on the part of energy consumers. Most energy consumers are not in the energy business and thus require significant training and education to achieve this level of sophistication. Consumers who are unable or unwilling to commit the time and expense necessary to bid into the CAISO markets may, nonetheless, be good candidates for participation in a Load Modifying Resource DR program.

The implementation processes for full participation in the CAISO wholesale energy markets are complex because the Supply Resource DR must be dispatchable as a result of a complex optimization market clearing process; they are also compensated from the CAISO energy market. Therefore, the Scheduling Coordinator that represents the Supply Resource DR needs to adhere to similar market participation rules, related to registration, bidding and scheduling, telemetry, certification requirements, resource performance requirements, and compliance obligations that are applicable to the conventional generation-like resources. However, the CAISO energy markets from their inception were mainly designed and implemented taking into account the characteristics, constraints and economics of the conventional generation-like resources. Other than Participating Load, Supply Resource DR was never an integral part of this design framework. Most Participating Loads are large pump loads. There are three categories of Participating Load that can participate in the CAISO markets: (1) Pumped-Storage Hydro Units; (2) Single Participating Load (i.e., pumping load or non-pumping load); and (3) Aggregate Participating Load (i.e., aggregated pump load or non-pumping load). These models have certain restrictions that constrain the market options available to DR programs (see Business Practice Manual for Market Operations, Version 38, Revised on January 6, 2014). For example, non-pumping Participating Load

Resources such as DR, that represents price sensitive Demand, if they have not executed a Participating Load Agreement with the CAISO, can use the ordinary Non-Participating Load model and bid in the Day-Ahead Market (DAM). They may not be bid-in to be curtailed in Real-Time Market (RTM). The Proxy Demand Resource (PDR) model, which was subsequently developed, is clearly an improvement over the Participating Load model, but it was not designed to specifically integrate existing utility DR programs into the CAISO wholesale markets.

Therefore, it is critical as we move forward to seek to increase the participation of Supply Resource DR into the CAISO's wholesale energy market to revisit the rules and protocols of engagement of the current market architecture with the clear objective to simplify the market participation processes.

Q 8 Does load modifying resource DR contribute to price formation in the CAISO energy market?

A 8 Yes. The Commission has defined a Load Modifying Resource (or a Demand Side DR Resource) as a resource that reshapes the CAISO's overall net load curve (CPUC D.14-03-026 Ordering Paragraph 3) (i.e., the load curve netted from the total injection of renewable energy) and is not bid into the CAISO energy markets or dispatched through the CAISO energy markets as a conventional generation-like product. The CAISO's net load curve is met by conventional supply-side resources that schedule and bid into the CAISO wholesale energy market.

The reshape of the CAISO's overall net load curve by Load Modifying Resource DR can manifest itself in several ways:

1) Decrease the peak load;
2) Decrease the ramping down and ramping up curvature, resulting in a less steep load curve; and
3) Decrease the depth of the curve, resulting in a flatter net load curve.

The net effect of these Load Modifying Resource DR actions, if properly used, 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. The net load curve is served by conventional generation and Supply Resource DR. This means that the Load Modifying 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. It also means that Load Modifying Resource DR actions also reduce the need for flexibility resources. Therefore, Load Modifying Resource DR, even though it is not bid into the CAISO market like generation, directly impacts the wholesale market because its action directly results in load changes. As a result, one can conclude that Load Modifying Resource DR directly contributes to the price formation in the CAISO energy market.

A similar argument can be applied to the value of Load Modifying Resource DR's value on Resource Adequacy. Since Load Modifying Resource DR can reduce the system peak load, then the result is a lower Resource Adequacy requirement. Such programs may impact forecasts of load or demand. This means that fewer conventional supply-side resources need to be procured to meet this requirement. As a result, one can conclude that Load Modifying Resource DR actions can directly impact the value of RA contracts with wholesale integration requirements or the price formation of a future voluntary residual capacity auction.

See testimony of PG&E witness Dr. Zarnikau (Exhibit (PG&E-01), Appendix C) for an explanation of the basis for these points for electric markets in general.

Q 9 Are load modifying resources currently impacting the CAISO markets?

A 9 Yes. The CAISO Demand Response Resource User Guide Version 3.0 provides a description of the processes for incorporating Load Modifying Resource DR into the CAISO market. The processes, in summary, are as follows.

Day-Ahead Demand Response Programs are initiated through a manual process by LSEs or Demand Response Providers (DRPs) and are triggered based on various conditions such as the day-ahead forecasted temperature, day-ahead forecasted demand and high price forecasts. LSEs or DRPs submit the DR forecast to the CAISO by 10:00 a.m. the day ahead. The CAISO then adjusts the Residual Unit Commitment (RUC) procurement target based on the DR forecast. The forecast is broken out by sub-LAP. The RUC procurement target is based on the difference between the CAISO Forecast of the CAISO Demand (CFCD) and the energy schedule of the

Integrated Forward Market (IFM) for each Trading Hour of the next Trading Day. Further the CAISO adjusts the CFCD in real-time for the following trading day to reflect the DR information from the LSEs and DRPs.

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. By reducing the RUC procurement target, Load Modifying Resource DR directly benefit the market and the ratepayers.

Similarly, the DR adjustment to the CFCD ensures that the DR is carried through and accounted for when the CAISO commits additional generating units in the Real-Time Market (RTM) processes (STUC, RTUC and RTED).

In summary, it is very important for the Load Modifying Resource DR actions to be taken into account in the CAISO unit commitment processes, even if not bid in as PDR, PL or RDRR. These unit commitment procurements (RUC and RTM) by the CAISO constitute additional costs to ratepayers that can be avoided if Load Modifying Resource DR actions are properly recognized by the CAISO.

Day-Of Price Responsive Demand Response Programs can be also initiated by a manual process by LSEs and DRPs. They may be initiated based on CAISO system conditions or other specific triggers such as forecasted load, expected heat rate indicator, forecasted high prices, local distribution systems conditions, CAISO Alerts or Warnings, forecasted or actual temperature, etc. Under Day-of Price Responsive Programs, customers are notified the same day the event occurs and, depending on the program, are given as much as three-hours notice to as little as 15-minutes notice to curtail load. These DR adjustments reduce the CFCD and ensure that Day-Of Price Responsive Demand Response Programs are incorporated in the Real-Time Market.

Q 10 What changes can be made to the CAISO processes to better coordinate load modifying resources with the CAISO market?

A 10 The presented processes are manual and do not cover all the CAISO market elements. The following improvements are recommended as possible ways to improve Load Modifying Resource DR coordination with the CAISO. 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 stakeholders. They are in the areas of automation and market rules changes.

Automation

By 8:00 a.m. each day during the summer months, the LSE fills out an Excel spread sheet called "Daily DR Report" and submits to the CAISO Operations by email. The spreadsheet includes all of the LSE's Day-Ahead and Day-Of Programs and specifies the amount of load that is scheduled to be called and the amount of load that is available to be called. If a Day-Ahead DR event is called after the 8:00 a.m. report has been sent, then the LSE fills out the data that pertains to the specific DR Program that will be called and sends the report to the CAISO no later than 10:00 a.m. the day ahead which corresponds to the Day-Ahead Market close time.

The IOUs, through this spread sheet notification procedure inform the CAISO of when and where load will be dropped through DR. This process allows the CAISO to adjust its load forecast and thus optimize its Security Constrained Unit Commitment and Economic Dispatch decisions to the best available information. CAISO operators have certain discretion to adjust the computed generated load forecasts if they determine that they are not accurate. For example, exercising their operating judgment they may adjust the load forecasts upwards under certain system conditions, if the resulting load forecasts are lower than expected, for example during a heat wave, etc.

There are subsequent communications between the CAISO and the LSE/DRP related to the initial DR results seven days following the trading day and final results by end of the calendar year.

One recommendation is that this manual process could be automated and potentially become more efficient. Email transmission would be deployed only as a back-up way of communications.

Market Rules Changes

The CAISO sets the Ancillary Services requirements based on the CAISO Forecast of the CAISO Demand (CFCD). For example, the Regulation Reserve MW requirement is set as a percentage of the CFCD for the hour based upon its need to meet the Western Electric Coordination

Council (WECC) and North American Electric Reliability Corporation (NERC) performance standards. The percentage targets can be different for Regulation Up and Regulation Down. The percentage targets can also vary based on the hour of the operating day. Also the CAISO sets the operating reserve procurement target in accordance with WECC Minimum Operating Reliability Criteria (MORC) requirements which take the CFCD into account.

Since Load Modifying Resource actions impact the CFCD, they should be considered to adjust downwards the Ancillary Services requirements the CAISO is using to procure ancillary services products.

Q 11 Are there ways to reduce the cost and complexity of bidding Supply Resource DR into the CAISO market?

A 11 Yes, but it will require changes in CAISO rules and processes.

In the following we briefly present some key market participation requirements and offer some ideas that if implemented may reduce the cost and complexity of participation of Supply Resource DR into the CAISO's wholesale energy market. In general the CAISO markets are complex (see CAISO's pricing forum held on April 22, 2014, http://www.caiso.com/Documents/Agenda-PricingForumApr22_2014.pdf) and every effort should be made to ensure that market participation is less costly and less complex. This testimony is not intended to provide a complete treatment of this subject. Although many of these topics are complex enough to warrant further analysis and debate, the scope of this testimony is to provide some initial guidance for recommendations.

Qualification and Registration

In summary we propose the following recommendations that, if implemented, have the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Allow Supply Resource DR to span sub-LAPs if it is appropriate to assume that the additional congestion, if any, resulting from the DR resource dispatch is small.
- Allow Supply Resource DR to span LSEs.
- Simplify Rule 4 below.
- Simplify Rule 5 below.
- Map sub-LAPs to LCAs.

- Allow, as an option, one to many relationships between Resource ID and registrations in the CAISO's Demand Response System (DRS).

Prospective Supply Resource DR must meet the prescribed qualification requirements as set forth by the CAISO's market participation protocols (see CAISO's Draft Final Proposal for the Design of Proxy Demand Resource (PDR), revised on August 28, 2009). Further, since multiple parties (LSEs, DRPs, UDCs) may be impacted, a registration process is needed to manage the approval process for the registration of new DR resources as well as to manage the movement of individual accounts between a DRP and between a DRP's Supply Resource DR. Further, registration provides visibility and auditability of aggregated participation to multiple entities For example, if a DR resource is an aggregation of customers, they must all be located within the same sub-LAP or Custom LAP and be associated with the same LSE. A DR resource must meet necessary minimum metering requirements to participate in the target program, including the ability to provide interval metering data at the necessary granularity.

The registration requirements and process enables the following:

a) Capture required characteristics of each Supply Resource DR;
b) Provide a series of controls to ensure the appropriate acknowledgement to required parties of DR registrations, most important being those to the LSE and/or UDC so that changes to functions such as demand forecasting can be implemented, and UDC and LSE DR program participation rules can be followed; and
c) Unique identification of the Supply Resource DR to rule out duplicate or overlapping DR registrations.

The creation of the location and the registration is the first step toward DR participation and involves a workflow process that requires the involvement by the corresponding LSE and UDC for the resource. This registration process should be initiated by the LSE or DRP that is representing the resource. Some notable registration requirements are the following:

1) Aggregations must contain customers that are all associated with the same LSE and UDC. In other words, locations from multiple LSEs or

UDCs cannot be combined into one aggregation registration. This means that it is impossible to integrate retail demand response programs into one aggregation unless they are already segmented by LSE.

2) Customers contained in an aggregation must also be within the same sub-LAP. This means that it is impossible to integrate retail demand response programs into one aggregation unless they are already segmented by sub-LAP. Also as sub-LAP boundaries can change over time, there is a risk of invalidating Supply Resource DR.

3) Once an aggregation is registered, the DRP cannot change the makeup of that registration without having to resubmit the aggregation for approval.

4) The registration is considered as a whole and not on an individual resource basis. This means that if a specific customer within an aggregation cannot actively participate in a specific event, the LSE/DRP must consider the impact of that condition before bidding in that registration. This "all or nothing" registration requirement is a major impediment to the integration of retail programs into the CAISO's wholesale energy market and should be revisited.

5) If a specific customer within an aggregation is no longer available for participation, the LSE/DRP must immediately resubmit the registration for approval by replacing the customer with another, or simply deleting it. This requirement is a major impediment to the integration of retail programs into the CAISO's wholesale energy market and must be revisited.

The current framework makes it difficult for LSEs/DRPs to increase their portfolio and build resources of sufficient size. The following are recommendations that, if implemented, have the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Allow Supply Resource DR to span sub-LAPs assuming that the additional congestion resulting from the DR resource dispatch is small.
- Allow Supply Resource DR to span LSEs
- Simplify Rule 4 above
- Simplify Rule 5 above

Another issue related to sub-LAPs is that they do not coincide with the Local Capacity Areas (LCA) which are used for Resource Adequacy by utilities. This is an aggregation limitation that poses a risk to LSEs/DRPs for developing a sizeable portfolio of Supply Resource DR and for managing target events to support local needs. A potential market configuration adjustment could be to:

- Map sub-LAPs to LCAs

The CAISO deploys the Demand Response System (DRS) for registering demand response locations and managing the overall registration process, the meter data submission, and the calculation of energy measurement for the participating Supply Resource DR. The DSR system will likely need to become more flexible to be able to manage Supply Resource DR with a large numbers of customers and locations (i.e., mass market) resources, process frequent changes to registrations and maximize the availability of registered resources and the effectiveness of the overall program. For example, currently DRS is only allowing a one to one relationship between registration and Resource ID. It would be helpful if DRS would allow, as an option, one to many relationships between Resource ID and registrations (see Business Practice Manual for Metering, Version 8, Revised on January 3, 2014).

- Allow, as an option, one to many relationships between Resource ID and registrations in the DRS system.

<u>Scheduling and Bidding</u>

In summary we propose the following recommendations that, if implemented, have the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Revisit and possibly modify the 0.1 MW minimum load drop requirement.
- Revisit and possibly allow partial de-rates for Supply Resource DR.

A LSE/DRP can bid aDR resource into the CAISO markets through a Scheduling Coordinator (SC). Once a LSE/DRP becomes certified for participation in the CAISO markets and registers its resources, actual participation proceeds with the submission of bids for energy and/or capacity products (e.g., Ancillary Services). The LSE/DRP's preparation of market bids involves the collection of aggregated data of its end-use customers, and forecasting the availability of price responsive resources for the operating day, as well as business decisions such as determining its bid price.

Each DR resource must have a unique resource ID and be registered in the CAISO master registry (Master File). The DR would be modeled as a pseudo- generator and bid at the node, custom load aggregation point, or sub-LAP level, as applicable. Supply Resource DR, such as PDRs, may not be self-scheduled and must bid at a non-zero price (see CAISO's Draft Final Proposal for the Design of Proxy Demand Resource (PDR), revised on August 28, 2009).

A SC that represents a LSE/DRP can bid into the following markets:

a) Day-Ahead Energy Market (DAM) including the Residual Unit Commitment (RUC);
b) Day-Ahead and Real-Time Non-Spinning Reserve markets; and
c) The Real-Time Energy (RTM) market.

Under the current market rules, the SC submitting a bid for Supply Resource DR is subject to the same process, bid validation, and market timelines as for any other generating bid submitted to the CAISO markets.

Supply Resource DR, deploying the PDR model, must have a minimum load size, typically 0.1 MW (100 kW) to participate in the CAISO market (minimum load drop requirement). Smaller loads may be aggregated together to achieve the 0.1 MW threshold. However in many cases the aggregation is over several sub-LAPs and under the current rules this is not allowed. As such, under current rules in some cases, and depending on the technology deployed, DR cannot qualify as a PDR to fully participate in the CAISO markets. This restriction needs to be revisited. The following is a recommendation that, if implemented, has the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Revisit and possibly modify the 0.1 MW minimum load drop requirement.

Another area where changes may be beneficial is related to the management of outages. Specifically, PDRs are not allowed to submit a partial de-rate. In the case of de-rate they must declare their entire resource unavailable. This restriction exposes the LSEs/DRPs to replacement costs for the entire resource. This restriction needs to be revisited. The following is a recommendation that, if implemented, have the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Revisit and possibly allow partial de-rates for Supply Resource DR.

Notification

This section is included to provide a complete view of the high level processes LSEs/DRPs follow to participate in the CAISO markets even though we do not propose any specific recommendations that, if implemented, could potentially reduce the cost, complexity and risk to LSEs/DRPs.

LSEs/DRPs need to be aware of DR enrollments and schedule changes that may occur between day-ahead and real-time. LSEs base their load schedules on the actual usage of the customers whom they serve, and lack of knowledge about DR schedule changes affecting their customers could cause error in their demand forecasts.

Both the LSE and the DRPs have access to the following information on DR resources (see CAISO's Draft Final Proposal for the Design of Proxy Demand Resource (PDR), revised on August 28, 2009):

a) Day-Ahead Market Results: This report provides the day-ahead schedule information for the DR which would include scheduled quantities for energy and the capacity awarded for RUC and Ancillary Services (AS). There is no bid price information included in this report.
b) Expected Energy: This report contains the total expected energy for day ahead and real time for the DR. There is no bid price information displayed in this report.
c) Real-Time Dispatch information.
d) In the case where a LSE and a DRP are separate entities, the LSE is provided with read-only access to the reports listed above and only for the specific resource IDs of any DRs that are comprised of that LSE's customers. The DRP bidding the DR resource has access to the reports listed above in addition to all other available reports from the market that are relevant to the DR resource.
e) If the LSE and the DRP are the same entity, then both the LSE and the DRP have access to all available reports from the market that are

relevant to the DR resource. Both the LSE and the DRP have access to the real-time dispatch information from the CAISO.

<u>Ancillary Services Requirements and Certification</u>

In summary, we propose the following recommendations that, if implemented, have the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Further develop with the participation of LSEs/DRPs and the CAISO a certification process that meets the Supply Resource DR characteristics.
- Introduce a resource option in the Master File, directly applicable to Supply Resource DR that treats the bid in MW quantity as the maximum available MW quantity.
- Allow LSEs/DRPs the flexibility to determine the baseline approach that best fits their operational schedule profile and clearly develop the CAISO approval process.

Demand response may participate in the Day-Ahead Market (DAM) including RUC, the Real-Time Energy Market (RTM) and the Day-Ahead and/or Real-Time Non-Spinning Reserve Market. The requirements for qualifying Participating Load resources to provide Non-Spinning Reserve, and for participating in the market (bidding, settlement, etc.), also apply to Supply Resource DR which want to bid into the CAISO wholesale energy market because the structure of using the proxy generator for the real-time demand response is the same as that used for Participating Load.

Also, Supply Resource DR will undergo a certification process, which is similar to the one used to certify AS providers of other generation-like resources. Supply Resource DR must be equipped with an Automated Dispatch System (ADS) terminal for receiving dispatch instructions from the CAISO on a 5-minute basis and should demonstrate the technical capability of reducing demand following a dispatch instruction. The minimum and maximum demand reduction will be certified for DR in the IFM, RUC, and RTM. The maximum demand reduction within 10 minutes from receiving a dispatch instruction will be certified for the Non-Spinning Reserve provision. These demand response quantities will be included in the Master File for bid validation purposes. Certain other technical characteristics will also be certified and included in the Master File: maximum base load, ramp rate functions for load reduction and load pickup, notification time (time delay between initiating demand response and actual demand reduction), minimum down and up times, and maximum number of daily demand responses from base load. Naturally, resource owners strive to achieve the maximum certification amount possible to ensure bidding flexibility and revenue potential. The same would apply to LSEs/DRPs.

Supply Resource DR will be metered and reported individually and separately from other load. Hourly metering will be required for participation in the IFM and RUC, and 5-minute metering will be required for participation in the RTM and for providing Non-Spinning Reserve.

The current certification process poses several challenges for Supply Resource DR that strive to integrate in the CAISO wholesale energy and ancillary services market. For example, many DR programs are weather sensitive and achieving the maximum certification amount is very challenging. Even more importantly, in the future more and more DR programs may become part of an aggregation resource. The configuration of aggregation resources may change frequently as the aggregation grows over time or DR programs migrate to other aggregations. This fact poses a challenge in the certification process as the potential for frequent certification tests substantially increases and the chance for accurate capacity certification may be diminished. This is a critical issue because the accuracy of the certification process directly impacts the power system reliability because it affects the capacity the CAISO procures to ensure system reliability. We propose the following recommendation that, if implemented, has the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Further develop with the participation of LSEs/DRPs and the CAISO a certification process that meets the Supply Resource DR characteristics.

A related issue to the variability of the aggregation configuration and size, which has a wider impact beyond the ancillary service markets, is the frequent changes of the maximum certified amount. The CAISO is using this value in several market processes. For example, in the exceptional dispatch application, it is critical to understand that this maximum certified quantity may not be available for many of these DR programs, thus creating substantial risks to the DR owners who want to fully integrate their Supply Resource DR into the CAISO wholesale energy market. Recognizing the variability of the capacity of the Supply Resource DR we propose the following recommendation that, if implemented, has the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Introduce a resource option in the Master File, directly applicable to Supply Resource DR that treats the bid in MW quantity as the maximum available MW quantity.

The settlements approach for Ancillary Services may not be workable for several reasons. For example it is generic and not customized to each DR program's operational schedules. The CAISO allows a more flexible approach but the actual process for getting CAISO approval is not very clear. The following is a recommendation that, if implemented, has the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Allow LSEs/DRPs the flexibility to determine the baseline approach that best fits their operational schedule profile and clearly develop the CAISO approval process.

Metering and Telemetry

In summary we propose the following recommendations that, if implemented, have the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Relax the communications protocols and allow ICCP (Inter Control Center Communications Protocol) as an alternative communication protocol for telemetry.
- Relax the requirements for the use of dedicated leased lines, such as the Energy Communications Network (ECN).
- Relax the restrictions requiring the telemetry gateways be sited within the same sub-LAP as the telemetered resources.
- Increase the threshold of 10 MW for telemetry for resource aggregations.
- 15-minute recorded meter data should be accepted provided the SC parses the 15-minute recorded SQMD into three equal 5-minute intervals.

A Scheduling Coordinator for a SC Metered Entity, including a DR resource, which represents a LSE/DRP must sign a Meter Service Agreement with the CAISO. The Scheduling Coordinator is responsible for providing Settlement Quality Meter Data (SQMD) for the SC Metered Entities it represents. Such agreements specify that the Scheduling Coordinator requires their SC Metered Entities to adhere to the meter requirements of the CAISO applicable to Scheduling Coordinators for SC Metered Entities. The CAISO will use the SQMD in conjunction with a Customer Baseline Load calculation (CBL) to determine the financial settlement between the CAISO and the Scheduling Coordinator for the Demand Resource (see Business Practice Manual for Metering, Version 8, Revised on January 3, 2014).

When Supply Resource DR is connected to a UDC's Distribution System, the responsible SC must submit interval SQMD adjusted by an estimated Distribution System Loss Factor (DLF) to derive an equivalent grid level measurement. Such estimated DLFs must be approved by the relevant Local Regulatory Authority prior to their use. The SC must aggregate its equivalent grid-level meter data for its SC Metered Entities.

SQMD to the CAISO must be submitted to the CAISO no later than the day specified in the CAISO Payment Calendar. SQMD must be submitted using one of CAISO's approved Meter Data Exchange Formats (MDEF) or a CSV format. LSEs/DRPs are able to view the content of their data (status flag, values, and time stamp) for a given resource to assist them in analyzing their Settlement Statements. The system supports versioning to enable participants to view any version of meter data submission individually or concurrently.

Supply Resource DR can offer ancillary services to the CAISO if it can meet the standards and eligibility for that particular ancillary service. LSEs/DRPs that wish to have Demand Resources participate in the CAISO's ancillary services market are required to first establish real-time visibility of that Demand Resource with the CAISO's Energy Management System (EMS) on a four-second basis. Resources over 10 MW should also provide telemetry to ensure visibility for the real-time operation of the grid and compliance to mandatory NERC and WECC reliability standards.

A Demand Resource's real-time consumption must be securely conveyed to the CAISO through telemetry using an Energy Data Acquisition and Concentration (eDAC) device or system, or any other CAISO approved method or device for securely conveying this information to the CAISO's EMS. Currently the telemetry process poses certain challenges to Supply Resource DR willing to fully integrate into the CAISO wholesale energy market. The following are a few recommendations that, if implemented, have the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- Relax the communications protocols and allow ICCP (Inter Control Center Communications Protocol) as an alternative communication protocol for telemetry;
- Relax the requirements of use of dedicated leased lines, such as the Energy Communications Network (ECN);
- Relax the restrictions requiring the telemetry gateways be sited within the same sub-LAP as the telemetered resources; and
- Increase the threshold of 10 MW for telemetry for resource aggregations.

Finally, SCs which represent LSEs/DRPs, must record meter data in Standard Time as follows:

a) At 5-minute intervals for Demand Resources that provide Ancillary Services or 5-minute dispatchable Real-Time Imbalance Energy. The preference is to use interval data that has been recorded in 5-minute intervals. However, many larger commercial and industrial customers have meters that read only on 15-minute intervals. This poses a challenge to Supply Resource DR.

b) At one hour intervals for day-ahead energy.

The following recommendation, if implemented, may have the potential to reduce the cost, complexity and risk to LSEs/DRPs.

- 15-minute recorded meter data should be accepted provided the SC parses the 15-minute recorded SQMD into three equal 5-minute intervals.

Q 12 How substantial are the incremental benefits of dispatching DR in the CAISO market as supply relative to dispatching the same DR as load?

A 12 The incremental benefits are very small. This point is covered well in the testimony of Dr. Zarnikau (Exhibit (PG&E-01), Appendix C) regarding electric markets in general. I will note where this applies to the specifics of the CAISO market.

There are two types of benefits of DR: (1) capacity benefits; and (2) energy benefits. The current DR programs derive most of their benefits from the value of capacity, because they are only dispatched for a small number of hours. DR programs are currently available to the CAISO when and where needed and thus provide capacity value. The capacity value of DR is not increased by bidding into the markets as supply (PDR, PL or RDRP) except for ancillary services (A/S).

There is also an energy benefit from dispatching DR. This benefit is captured whether DR is represented as a load change or if it is bid as supply. Day-Ahead DR can be represented as a load change or bid in as supply (PDR, PL or RDRP). The energy benefit is generally much smaller than the capacity benefit because DR is usually only dispatched a small number of hours each year. However, there are times, during tight supply/demand balance, when a small amount of DR can provide a large benefit by significantly reducing load when and where needed. But this effect of DR will materialize whether the DR is treated as load or supply in energy markets (for A/S markets the DR would need to be supply (i.e., PDR or PL)). The major value of bidding in DR as Supply Resources in the CAISO markets will likely come from the participation in A/S markets.

In summary, DR programs providing day -ahead and real -time energy have practically similar benefi ts either as load changes into the CAISO markets (using the CAISO Demand Response Resource User Guide Version 3.0) or as supply (PDR, PL or RDRP) . The arguments presented earlier regarding Load Modifying Resource DR as a major factor in reshaping the CAIS O's net load curve further give credence to the claim that the derived benefits of bidding in and dispatching DR in the CAISO market as supply is small relative to dispatching the same DR as load. In this case the DR is locally dispatched by the LSE/DRP consistent with the procedures specified in the CAISO Demand Response Resource User Guide.

As the DR market matures, more experience is gained by all parties involved, and market rules and processes are simplified, the expectation is that the amount of Supply Resource DR will increase, but this transition should be deliberate and methodical to prevent the devaluation of current DR programs. Otherwise, the migration of IOU DR programs into the CAISO wholesale energy market may result in a difficult transition for IOU DR participants and ultimately have a negative impact on program enrollment, retention and customer satisfaction. Also, all DR programs (Supply Resource DR or Load Modifying Resources) can already be dispatched for reliability reasons if needed by the CAISO.

From the CAISO perspective, Supply Resource DR bid into the CAISO wholesale energy market is optimized and dispatched along with all other conventional generation-like resources to support a security constrained economic dispatch and unit commitment solution. Therefore, and from the system perspective, a Load Modifying Resource, dispatched by the LSE/DRP, may lead to a theoretical sub-optimal dispatch since the LSE/DRP does not have full visibility of the entire transmission grid as the CAISO does. Given that DR resources are highly use-limited resources and are targeted to extreme conditions (e.g., very high prices, extreme hot weather, etc.) it is unlikely that over the course of the year this theoretical sub-optimal dispatch can lead to less efficient solutions in any substantial way. We claim that given the extreme conditions on the grid under which the DR resources are expected to be activated, the CAISO centralized optimization is unlikely to produce a more efficient dispatch solution than the one produced by the IOUs by the optimization process of their DR resources under the same conditions. It is logical to think of this possible sub-optimality as an additional constraint imposed on the optimization clearing algorithm similar to several others currently present in the market, such as self-scheduling of conventional generation-like resources.

The imposition of such a constraint can be relaxed over time as more experience is gained by all parties involved and the market matures. In any case, it is critical to understand that the decision to participate in the CAISO wholesale energy market should be left to LSEs/DRPs based on economics.

Q 13 Will a transition to large scale integration of DR into the CAISO market as supply take a significant amount of time to be valuable?

A 13 Yes. Participation of DR resources in the CAISO wholesale energy market requires substantial input and interaction with end-use customers. Further it requires an in-depth understanding of the end-use composition of the customer's electricity demand and a baseline methodology which accurately measures the consumer's actual performance. The discussion above of possible improvements in the existing CAISO processes (and describing those processes) for Supply Resource DR demonstrates the complex nature of participation. It will take significant time to achieve integration efficiently on a large scale. 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 the right way to move forward. Instead, deployment of pilot programs to integrate small amount of DR into the market while at the same time simplify the CAISO market rules for full participation is the right way for moving forward and developing a comprehensive path that will lead to large integration of Supply Resource DR in the longer term.

Further, most energy consumers are not in the energy business and thus require significant training and education to achieve the required level of sophistication. Clearly, this also implies that the transition to large-scale integration of DR into the CAISO market will take a significant amount of time to be valuable. Further, it should be implemented in a way that does not devalue the existing Load Modifying Resource DR programs. Consumers who are unable or unwilling to commit the time and expense necessary to bid (or be bid) into the CAISO markets may, nonetheless, be good candidates for participation in Load Modifying Resource programs.

Q 14 Do DR resources need to be bid as supply resource DR as opposed to being dispatched as load modifying resource DR for the CAISO wholesale electricity market to work?

A 14 No. As we discussed earlier Load Modifying Resource DR reshapes the CAISO's net load curve which is met by conventional supply-side resources that schedule and bid into the CAISO's wholesale energy market and set the LMP prices at every price location of the CAISO's transmission grid. This has positive market and operational benefits. Clearly the CAISO energy markets can work effectively even when DR resources participating in the CAISO markets are Load Modifying Resource DR. Experience from other organized ISO wholesale energy markets give credence to this claim. See testimony of Dr. Zarnikau (Exhibit (PG&E-01), Appendix C) for a general discussion of how Load Modifying DR can work well in electricity markets and how it works well in ERCOT.

In summary, Load Modifying Resource DR may lower market prices, assist LSEs in managing local congestion on the distribution system, and contribute to the reliable operation of the CAISO wholesale energy market.

Q 15 Do DR resources need to be bid as supply resource DR into the CAISO market as opposed to being dispatched as load modifying resource DR to contribute to CAISO wholesale market price formation?

A 15 No. As we discussed earlier a Load Modifying Resource DR directly contributes to the price formation of the CAISO energy market. The net effect of the Load Modifying 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 the Load Modifying 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 Modifying Resource DR, even though not bid in like generation in the wholesale market, directly participate in the market since their action directly result in load changes. As a result, one can conclude that the Load Modifying Resource DR directly contributes to the price formation in the CAISO energy market.

See testimony of Dr. Zarnikau (Exhibit (PG&E-01), Appendix C) for a general discussion of how Load Modifying DR can contribute to wholesale market price formation.

Q 16 Does this complete your direct testimony?

A 16 Yes, it does.

PACIFIC GAS AND ELEC TRIC COMPANY

APPENDIX B

DIRECT TESTIMONY OF SPENCE GERBER

OLIVINE, INC.

PACIFIC GAS AND ELECTRIC COMPANY
DIRECT TESTIMONY OF SPENCE GERBER

Q 1 Please state your name and business address.

A 1 My name is Spence Gerber. My business address is 2010 Crow Canyon Place, Suite 100 San Ramon, California.

Q 2 Briefly describe your responsibilities at Olivine, Inc. (Olivine).

A 2 I am employed by Olivine Inc. as a Senior Consultant. Olivine, a certified CAISO Scheduling Coordinator (SC) and Demand Response Provider (DRP), supports the integration of renewable and emerging technology resources into the wholesale market and in retail applications to ensure that viable alternatives exist to customary generation. Olivine uses its SC status, operational infrastructure and technology platform to participate directly in the CAISO markets and to provide utilities and other providers the opportunity to test and integrate resources in a cost-effective manner to support a market transformation to clean power options. In this role, I provide management consulting support in the development, implementation and operation of distributed energy resource programs that spans demand response as well as other emerging resource technologies, including the integration of demand response into the CAISO market.

Q 3 Please summarize your professional background.

A 3 I have over 30 years in the electric utility industry ranging from retail customer accounts to system operations, wholesale trading and management. Prior to being employed by Olivine, I progressed through a variety of positions at Portland General Electric in Portland, Oregon before joining the California Independent System Operator (CAISO) in 1997. In addition to establishing the interchange scheduling group during CAISO start-up, I held the roles of Director of Settlements and MRTU Program Director until I left in 2006. From 2006 to 2010, I worked at APX serving as MRTU Readiness Project Manager and as a management consultant on various APX client engagements including system operations, demand response and energy efficiency projects.

Q 4 What is the purpose of your testimony?

A 4 The purposes of my testimony is to

1) Demonstrate that bidding PG&E's current DR programs into the CAISO market is a complex and nuanced process,

2) Identify opportunities to reduce the cost and complexity of bidding DR resources in the CAISO market,

3) Describe some of the challenges of bidding PDR into the CAISO market experienced in the IRM2 pilot so far,

4) Identify the limitations on the amount of current DR programs that may be bid into the CAISO markets.

<u>Bidding DR Programs Into the CAISO Market is Complex</u>

Q 5 What is your expert opinion about bidding PG&E's current DR programs into the CAISO market?

A 5 Bidding existing utility programs into the CAISO market is currently a complex and nuanced process. Olivine prepared a report for PG&E entitled, "Evaluation of PG&E's Demand Response Programs for Wholesale Market Integration"[1] (Integration Report) to determine the feasibility of integrating existing PG&E DR programs into the CAISO market based on the current design of the CAISO market and the PG&E DR programs. This report considered all of PG&E's DR programs, and presumed no changes to CAISO processes or the programs themselves other than those already in development. The main conclusion of the Integration Report was that a number of the current programs are a poor fit for integration at this time while there were others that were reasonably compatible based on the parameters of our analysis. For those programs that were structurally compatible, it was possible to integrate portions of the enrolled capability over a reasonable time horizon.

Q 6 What process did Olivine use in the Integration Report to reach this conclusion?

A 6 In completing the initial assessment for market compatibility of all programs we utilized two main categories for screening.

The first screen scored programs as currently designed and operated on their ability to meet resource make-up and market design parameters including the feasibility of dealing with registration requirements due to

1 Appendix E.

issues such as fluctuation among program enrollees, and manual registrations at the CAISO.[2]

The second primarily examined the compatibility of program operations and market timelines for dispatch and notification.[3] During this process we identified programs that had a higher level of feasibility for near-term integration and completed further assessment on those programs. For those programs that were deemed of higher feasibility for integration, only a portion of each program was identified as being feasible to bid into the market in the near term.

Q 7 What specifically prevents an existing DR program with compatibility from being bid into the CAISO market in its entirety?

A 7 MW quantities from utility DR programs must be transformed into supply resources through a process that conforms to a strict set of CAISO parameters. Currently, the least complex process for representing DR program MWs as a resource are the Proxy Demand Resource (PDR) for economic bidding, and Reliability Demand Response Resource (RDRR) for emergency programs. Both PDRs and RDRRs require the identification and registration of all individual physical locations (accounts) that are included in a load reduction. These resource types can only contain locations within a single CAISO Sub Load Aggregation Point (Sub LAP) and served by a single Load Serving Entity (LSE).

Q 8 If the PDR and RDRR are the least complex processes for converting programs into resources, how does this contribute to the complexity of integrating a program?

A 8 The current resource registration process requires PDRs and RDRRs be contained within a single Sub LAP and only contain accounts from a single LSE. One of the difficulties lies in the fact that the PG&E service territory is subdivided into 16 separate Sub LAPs. Further adding to the difficulty is that existing DR programs contain both bundled and non-bundled customers. Subdivision of a DR program portfolio into multiple resources requires a process to distribute the DR provider's offer across numerous

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2 Integration Report Section 4.2.1.2.

3 Integration Report Section 4.3.1.

resources and maintain their coordination from bid to bill. For programs with system-wide aggregations multiple resources would need to be created for each Sub LAP and LSE combination.

Q 9 How does division of a DR program with a system-wide aggregation into PDRs in each Sub LAP create additional complexity?

A 9 Within each Sub LAP a PDR will have its own Locational Marginal Price (LMP) based on the differences in congestion and losses among the various Sub LAPs. The CAISO dispatches resources based on merit order (subject to security constrained economic dispatch and unit commitment) and there will be intervals (an hour for the Day Ahead market) when some PDRs associated with the system-wide aggregation clear the market and others will not, even when their bid price is the same. For a DR program that is designed and/or required by tariff to have events called on a program-wide basis, there is no guarantee that the entire aggregation will be dispatched by the CAISO.

Q 10 Is there any different treatment of DR resources that has to be considered when bidding into the CAISO market?

A 10 Specific to the actual process of bidding DR into the CAISO market, existing rules under FERC Order 745 require that only DR resources dispatched above a threshold price calculated monthly by the CAISO, or a net benefits test (NBT), can be compensated at the full LMP. Further the California Public Utilities Commission (CPUC) requires that DR that contains utility bundled customers be bid at or above the NBT.[4] Under certain circumstances DR programs that would otherwise be cost effective for dispatch when compared to traditional resources, might not clear the market if bid at the NBT.

Q 11 Are there any other aspects related to the NBT that create complexity and challenges?

A 11 Yes. As part of the CAISO implementation of the NBT, any DR paid below the NBT creates a load adjustment (commonly referred to as a Default Load

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4 CPUC D.12-11-025 OP 1 - All demand response providers bidding bundled customers' loads into the California Independent System Operators' wholesale energy market must submit bids that are at or above the net benefits test.

Adjustment or DLA) that increases the LSE metered demand.[5] While the requirement by the CPUC to bid above the NBT was intended to ensure that DR would be paid above the NBT to avoid the LSE load adjustment, the CAISO pays resources the real-time energy price for any delivery in excess of the dispatched amount. This means that if there is over delivery on a PDR (the amount of load reduction is greater than what was dispatched) and if the real-time price is below the NBT, then a load adjustment is added to the LSE metered demand and they effectively pay for the corresponding delivery at the real-time price.

Reducing Cost and Complexity

Q 12 Are there ways to reduce the cost and complexity of bidding Supply Resource DR into the CAISO market?

A 12 Yes, there seem to be some changes that could be considered in future retail program design as well as by the CAISO.

Q 13 What are possible ways to reduce the complexity and cost of bidding of Supply Resource DR?

A 13 Even without changes to the actual market algorithms and resource modeling, the cost and complexity of bidding Supply Resource DR into the market could be reduced by allowing Default Load Aggregation Point (DLAP)-wide PDR and RDRR registrations. This would better allow DR programs with system-wide aggregations to integrate into the market and reduce the number of resources that need to be maintained in the registration and bidding processes.

Q 14 Are there CAISO processes that would lend themselves to reducing cost and complexity if it were more broadly applied?

A 14 Yes, one recommendation the CAISO should consider that may lend itself to reducing cost and complexity is simplifying meter data requirements. The CAISO has a provision to allow alternative forms of measurement (i.e., baselines) for PDR and RDRR performance. Utility DR programs already involve collecting the necessary meter data to determine event resource performance, typically through a baseline process which in some cases is nearly identical to that which is used by the CAISO. Simply utilizing

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5 CAISO Tariff 11.5.2.4.

the DR program measurement would eliminate the need for the utility to provide a continuous string of meter data and for the CAISO to collect meter data and perform the calculation. With respect to accepting the utility program performance calculation (with a scaling factor to compensate for distribution loss factors), arguably the CAISO would allow this through their provision that allows alternative measurement if approved by the CAISO when the baseline calculations are sufficiently aligned. PDRs are already SC Metered Entities under the CAISO tariff and subject to an audit process for the meter data that they submit and this could be expanded to include their baseline process to alleviate accuracy concerns.

Q 15 Is there anything else that the CAISO could consider changing to simplify Supply Resource DR integration?

A 15 Yes. The complexity and risk associated with bidding DR as supply as a PDR could also be reduced by changing the method for outage reporting. PDRs, unlike other resource types, are not allowed to submit a partial de-rate of their resource and must declare the entire resource unavailable when submitting an outage report.[6] This can result in being exposed to replacement costs for the entire resource rather than just the portion that might have become unavailable. In the absence of the ability to submit a partial de-rate outage report, a reduction of the bid in quantity is an alternative for the DR provider to manage this risk.

Q 16 Will a transition to large scale integration of DR programs into the CAISO market as supply take a significant amount of time to be most valuable?

A 16 Yes, if the objective is to do this while minimizing the risk of losing existing DR MW.

Q 17 What creates the concern that integrating existing programs could result in the loss of existing DR programs MW?

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6 BPM for Outage Management Section 8.1.2 - …The only PMax derate permitted for PDR is a derate to 0 MW's (i.e., a PDR is either 100 percent available or 0 percent available, there are no partial derates of PDRs).

A 17 The PDR model was developed for the direct participation of DR by third party Demand Response Providers[7] and not specifically as a mechanism to integrate existing utility DR programs. While PDR is an improvement over the Participating Load model for purposes of DR integration, it is only one of several resource models (primarily generation and demand) and its implementation did not make any structural changes to existing CAISO market processes, most notably bidding (offer) and dispatch (notification) timelines. Existing DR programs have offer, event duration and notification timelines that are designed around a different set of needs than CAISO market timelines. While tariffs could be changed to better match market timelines, any such changes to existing DR programs must be done with diligent deliberation to make sure that changes do not erode the current quantities of DR available if participants cannot adapt to those changes.

Q 18 Are there other reasons to indicate that what is in place now is not the end state for DR participation in the CAISO market?

A 18 At this point there has been very limited production experience with PDR for the CAISO, utilities and other demand response providers that would reasonably inform the durability of the existing construct. Given the lack of experience and limited participation it would seem highly likely that changes will be needed as participation increases and the market develops.

My experience in these types of things creates an expectation that there will be a number of iterations in processes and models as markets develop.

This issue is why Olivine advocates transition projects and provides infrastructure to support integrating smaller quantities of DR, and allowing for feedback and changes on a path to large scale integration.

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7 February 16, 2010 - California Independent System Operator Corporation Docket No. ER10-765-000 Tariff Amendment to Implement Proxy Demand Resource Product.

P1, Paragraph 1 - The tariff provisions implementing the proxy demand resource product will satisfy the directives of the Commission's Order No. 719 that independent system operators should develop the capability to permit an aggregator of retail customers to bid demand response on behalf of retail customers directly into the ISO's organized markets to the extent permitted by applicable laws and regulations regarding retail customers.

IRM2 Experience

Q 19 Is there any experience with PDR that begins to inform issues with the existing processes and any concerns about the impact to DR participation?

A 19 Yes, Olivine is operating a DR Pilot, Intermittent Resource Management Two (IRM2), on behalf of PG&E. The Pilot is currently bidding into the CAISO market and has received market dispatches completing a bid-to-bill cycle for a PDR.

Q 20 What has the IRM2 Pilot revealed about some of the challenges that must be addressed for more DR to be bid into the CAISO market as supply?

A 20 In processing numerous inquiries from interested parties, it becomes apparent that under the current market design, there are at least two key issues that present a challenge for many of the prospects of participation.

Q 21 Can you describe the first of these two issues and why it creates a concern for broader integration based on Olivine's experience in IRM2?

A 21 The first issue is that non-IOU LSEs have been reluctant to support their customers' participation. There is an unclear requirement for an agreement between the LSE and DRP. The CAISO requires that the DRP ensure that any required bilateral agreement with the LSE be in place[8] and any payment arrangements between the DRP and the LSE be outside of the market, presumably in this agreement. Additionally, the LSE must be registered in the CAISO Demand Response System (DRS) to allow the PDR registration process to be initiated and completed. Generally non-IOU LSEs are unaware of this process and once informed, they have been reluctant to agree to: (1) have their customer enroll in a program with a direct incentive; (2) assume the risk of Default Load Adjustments (DLA); and (3) for those LSEs who are also demand response providers, have a customer enroll in another provider's program. When approached by both the customer and

[8] Section 12.3 of the BPM for Metering states - The PDR agreement requires that the DRP have sufficient contractual relationships with the end use customers, LSE, and UDC and meet any Local Regulatory Authorities' requirement prior to participating in the CAISO Markets.

the DRP (in the case of the IRM2 pilot, Olivine) the LSE is uncertain about what obligations that it will have if it executes an agreement and is reluctant to support direct participation. PG&E's DR programs, like other California utility DR programs, have significant participation from Non-Bundled customers and if acting as the DRP, will presumably have to execute agreements with Direct Access LSEs before registering these customers in a PDR.

Q 22 What is the second issue encountered in IRM2 and how has it had an impact on participation?

A 22 The second most prevalent issue has been uncertainty. As of now, IRM2 has only been approved through 2014 and for a minimal number of MW. We regularly have inquiries from entities who will need to adjust their approaches in order to fit into IRM2 and an uncertain future has caused issues. For example, emerging technology such as vehicle-to-grid integration might not yet have enough reliable dispatchable load to meet the 100kW minimum within a single SubLAP yet. Another situation was where a large resource was interested, but dropped out for various reasons including concern over marginal dispatch complications. The extension of IRM2 and the ability to transition resources of larger sizes into the program would alleviate many of these issues.

<u>Supply Resource Issues</u>

Q 23 Can all of PG&E's current DR programs be bid in as supply?

A 23 No. Generally, rate-based programs are not a good fit as Supply Resource DR and are better situated as Load Modifying Resource DR. Rate based programs include Critical Peak Pricing, Peak Day Pricing or Smart Rate. These programs encourage a participant's best efforts at reducing load and are not dispatchable by SubLAP. Those programs were excluded from consideration in the Integration Report prepared for PG&E. The specific reasons that certain other programs are a poor fit is detailed in the Integration Report that Olivine prepared for PG&E in Tables 3 and 4 of Appendix E. The most frequent element of incompatibility in addition to resource formation is the differences between the wholesale market timelines and program timelines for calling demand response events. While programs with Day Ahead products can be utilized in the CAISO

Day-Ahead Market, programs with Day Of products don't generally mesh with the CAISO Real-Time Market timelines that provide notification within two minutes of need and only for 5-minute durations. Ironically, the utility programs that are best situated for dispatch on short notice and might fit within the CAISO RT energy market (such as SmartAC) are the least compatible with the current resource registration process since they contain tens of thousands of accounts. While SmartAC can be called on short notice, the 5 minute duration of a dispatch interval doesn't mesh with the program parameters. There is the possibility that SmartAC could participate as Ancillary Service since it can be dispatched on short notice (10 minutes) and meet the duration requirement of 30 minutes.

Q 24 Will some DR MW be lost if all DR is required to bid as supply?

A 24 Yes. If all PG&E program DR had to be bid as PDR or RDRR, some DR customers and DR MW would be lost.

Within the limitations of creating PDR aggregations in a single Sub LAP and single LSE, some of the program MW would become orphaned because they do not meet the 100 kW minimum and cannot be included in the market under the current design. One possible solution to this would be for the CAISO to develop a DLAP wide PDR that would partially address this issue as well as creating a better opportunity to integrate existing programs that allow a PG&E system-wide enrollment. In addition, as indicated in my explanation of the IRM2 Pilot, some customers simply cannot meet the CAISO market requirements.

Q 25 If full integration requires a thoughtful and deliberate process, is there any opportunity to integrate programs in the near term that would help to inform that effort?

A 25 Yes. In further development of the recommendations in the Integration Report summarized in Table 8, Olivine and PG&E have continued to evaluate the opportunities for integration of PG&E DR programs in 2014. In the time that has passed from completing the Integration Report in December 2013, most impacts of manual business processes have been fleshed out. An update on this progress was shared with the CPUC staff on

April 10, 2014.[9] When stepping down from the full quantities of potential Supply Resource DR identified in the Integration Report, these quantities might seem trivial, but they are prudent given the challenges in the current environment.

Q 26 What is the total quantity of program MW that were considered in the Integration Report?

A 26 Based on 2013 ex-post values from September 2013, 795 MW.

Q 27 Is it in any way practical to consider integrating all 795 MW?

A 27 No, not at this time. Based on the first screen in the Integration Report, 355 MW were determined to not be compatible because of a poor fit due to design incompatibility. In the remaining 440 MW, 210 MW of the Base Interruptible Program (BIP) were removed due to uncertainties associated with the delayed implementation of the CAISO RDRR, reducing the quantity for integration consideration to 230 MW. RDRR is excluded as an opportunity for integrating the BIP since it is being re-released to CAISO market on May 1 but the functionality is to be confirmed in a market simulation that occurs later in May. Including it now would be contrary to best practices since market simulation typically reveals business and software flaws that require remediation.

Q 28 Of the remaining 230 MW, are there any other identified impacts that prevent the full quantity from being integrated without significant IT development?

A 28 Yes. Beyond the lack of CAISO Application Programmatic Interfaces (API) to the DRS which would alleviate some issues integrating programs with large numbers of customers and frequent turnover, there are other issues that were considered. Between the CAISO requirements of containing a PDR within a Sub LAP and the 100 kW resource minimum, an additional 90 MW are excluded. When eliminating programs that have significant Direct Access participation that would require the execution of a DRP and LSE agreement for non-utility LSEs, another 100 MW of DR is eliminated from near term integration. This leaves 40 MW of DR that can reasonably be considered for integration in the short term.

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9 Presentation provided in 4/15 *ex parte* notice and included as Appendix F.

Q 29 Can all 40 MW of those MW be integrated in 2014?

A 29 No. Given the heavy reliance on manual processes and the ability to reliably manage resources from the registration process through the bidding and the settlement process, is realistically in the neighborhood of 20 MW.

Q 30 Does this conclude your testimony?

A 30 Yes.

PACIFIC GAS AND ELEC TRIC COMPANY

APPENDIX C

DIRECT TESTIMONY OF JAY ZARNIKAU

ENERGY & ENVIRONMENT AL ECONOMICS (E3)

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

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

MAY 06, 2014

BEFORE THE
PUBLIC UTILITIES COMMISSION OF CALIFORNIA

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

INTRODUCTION AND QUALIFICATIONS

Q.1. PLEASE STATE YOUR NAME, OCCUPATION, 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. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A.2. I am the president of Frontier Associates LLC. My firm provides consulting assistance to energy consumers, electric and gas utilities, and government agencies on topics related to energy economics and pricing, utility cost allocation and rate design, forecasting, resource planning, energy efficiency program design and evaluation, and energy and regulatory policy.

Energy and Environmental Economic s, Inc. (E3) has provided assistance in my preparation of this testimony. My firm has worked with E3 on consulting projects in the past and I have coauthored several research papers with E3 staff.

Q.3. PLEASE STATE BRIEFLY YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL QUALIFICATIONS.

A.3. I have a Ph.D. in Economics from the University of Texas, Austin. I completed undergraduate studies in Business Administration and Economics at the State University of New York and McGill University in Canada.

From 1983 through 1991, I was employed by the Public Utility Commission of Texas ("PUCT"). At the PUCT, I served as the Manager of Economic Analysis from 1985 through 1988; as the Assistant Director of the Electric Division from 1987 to 1988; and as the Director of the Electric Division from September 1988 to 1991.

I held a faculty-level research position at The University of Texas Center for Energy Studies from 1991 through 1993.

I served as a vice president at Planergy, Inc., a firm providing consulting services, load curtailment programs, and energy efficiency programs, from 1992 to 1999.

Since 1999, I have been president of Frontier Associates LLC, an energy consulting firm with a staff of about 30 professionals.

I have written a number of reports and journal articles on the topics of electric utility resource planning, energy policy, rate design, demand-side management and electric utility restructuring. I have authored and coauthored a number of papers highlighting the importance of demand response in energy markets and analyzing specific demand response initiatives. Attachment JZ-A provides a list of publications which I have authored or co-authored and are related to this topic.

I teach graduate-level classes at the University of Texas as an Adjunct Professor. In 2001, per the direction of the PUCT, I worked with the staff of the Electric Reliability Council of Texas ("ERCOT") and stakeholders to create the Demand Side Working Group, which advises ERCOT on issues related to demand -side resources and since that date have actively participated in the Group, including serving as Co-Chair from 2000 to 2001.

Q.4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A.4. Yes. I have testified before the PUCT in over twenty -five dockets on behalf of the commission staff, electric utilities, and various consumer groups. My testimony has addressed a variety of topics including the design of industrial tariffs, interruptible rates, billing determinants, energy demand forecasting, computer modeling, fuel costs, energy and utility regulatory policy issues, and resource planning. I have also testified before the Railroad Commission of Texas on natural gas -related issues, in federal and state civil courts in Texas on utility matters, and testified or submitted testimony to regulatory authorities in Arizona, Arkansas, West Virginia, Virginia, South Carolina, and Pennsylvania.

Q.5. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A.5. I am appearing on behalf of Pacific Gas and Electric Company ("PG&E").

Q.6. HAVE YOU SUBMITTED TESTIMONY TO THIS COMMISSION IN THE PAST?

A.6. No.

Q.7. PLEASE DESCRIBE YOUR FAMILIARITY WITH CALIFORNIA'S ELECTRICITY MARKET?

A.7. My primary involvement has been with the Texas electricity market. I also monitor market activities in California, as it is one of the world's most important markets, and has been innovative and at the forefront in many areas.

However, I believe the fundamentals of a well-functioning market apply universally and that my experience with other markets provides insights into the role of demand response (DR) in California's electricity market. That said, I would defer to other witnesses offered by PG&E to contribute information and analyses about the CAISO's specific market rules, practices, and specific DR programs implemented by the load serving entities (LSEs) and the CAISO.

Q.8. WHAT IS YOUR ASSIGNMENT IN THIS PROCEEDING?

A.8. I was asked to explore the economic and reliability attributes of Load Modifying Resource DR resources, and examine the relative benefits and costs of any requirement that such resources be formally bid into the CAISO as Supply Resource DR.

I have not explored the treatment or value of DR as an ancillary service. It is my understanding that it is PG&E's position (consistent with my personal view) that any DR used to provide an operating reserve (i.e. ancillary service) should be bid-in and/or placed under the control of the CAISO.

CONSIDERATIONS AND CONCLUSIONS

Q.9. IN YOUR OPINION, WHAT FACTORS SHOULD THE CPUC CONSIDER IN DETERMINING WHETHER LOAD MODIFYING RESOURCE DR BE REQUIRED TO BE INTEGRATED INTO THE CAISO MARKET AS SUPPLY RESOURCE DR?

A.9. I suggest that the Commission consider each of the following:

- The relative value of each of the two types of DR – Load Modifying Resource DR and Supply Resource DR – as a long-term planning resource either (a) to reduce a load serving entity's (LSE's) resource needs, or (b) to meet a resource adequacy requirement (RAR).
- The relative impacts of the two types of DR on wholesale electricity prices.
- The costs and complexities that might be incurred by DR participants to convert or transition Load Modifying Resource DR to Supply Resource DR, since significant DR policy changes should be based on an assessment of both incremental costs and incremental benefits.
- Whether there are opportunities to better incorporate Load Modifying Resource DR into the CAISO market operations and dispatch without requiring such DR resources be converted to Supply Resource DR.

Q.10. WHAT CONCLUSIONS HAVE YOU REACHED?

A.10. The following are my conclusions:

- Load Modifying Resource DR provide similar reliability value compared to Supply Resource DR.
- The two types of DR resources may affect the CAISO energy market price in a similar manner.
- Based on my examination of the role of DR in market price formation and in the provision of planning reserves, I see no clear net benefit from dispatching DR as Supply Resource DR, rather than Load Modifying Resource DR, in the CAISO market.
- Any requirement that Load Modifying Resource DR be bid into the CAISO as Supply Resource DR will likely increase program costs and discourage DR program participation.
- Other organized wholesale markets (e.g., the Electric Reliability Council of Texas or "ERCOT" market) use DR resources as Load Modifying Resource DR and these markets work reasonably well.

LOAD MODIFYING RESOURCE DR AND SUPPLY RESOURCE DR

Q.11. WHAT IS LOAD MODIFYING RESOURCE DR?

A.11. The California Public Utilities Commission (CPUC) has adopted the following definition of Load Modifying Resource DR (Decision 14-03-026, Ordering Paragraph 2 and supported by Conclusion of Law 5):

Load Modifying Resource demand response reshapes or reduces the net load curve and Supply Resource demand response is integrated into the CAISO market.

As suggested in PG&E's comments of December 13 , 2013, Load Modif ying Resource DR is not formally bid into the CAISO markets or dispatched through the CAISO markets as a generation-like product.

Q.12. HOW DO ES LOAD MODIFYING RESOU RCE DR DIFFER FROM SUPPLY RESOURCE DR?

A.12. Load M odifying Resource DR reduces the need for conventiona l resources by reducing a LSE's net load.

Supply Resource DR act s as a supply -side substitute for the conventional generation resources used to serve a LSE's net load. It meets local and CAISO resource planning and operational requirements and is dispatched through the CAISO markets as products similar to conventional generation. As suggested in PG&E's comments of December 13, 2013, it may include Proxy Demand Response, Reliability Demand Response Resource, and Participating Load.

CONTRIBUTION OF LOAD MODIFYING RESOURCE DR TOWARD RESOURCE ADEQUACY REQUIREMENT

Q.13. DOES LOAD MODIFYING RESOURCE DR HELP MEET A LSE'S RE SOURCE ADEQUACY REQUIREMENT?

A.13. Yes. If durable in the long -term, Load M odifying Resource DR reshape s the LSE's load curve and reduce s the ne ed for conventional generation resources.

Such programs may impact forecasts of load or demand, and thus lower the need for future resources. This topic is further discussed in the testimonies of PG&E witnesses Mr. Luke Tougas (Chapter 2) and Dr. Alex Papalexopoulos (Ex PG&E-01, Appendix A).

Consider the simple example of a hypothetical LSE with a load forecast of 1000 MW before including the Load Modifying Resource DR of 100 MW. Suppose the resource adequacy requirement (RAR) is 115% of the LSE's load forecast, or 1150 MW (= 1000 MW * 1.15). After including the Load Modifying Resource DR resources (and prior to any consideration of avoided line losses) , the LSE's load forecast is 900 MW (= 1000 MW – 100 MW), implying a RAR of 1035 MW (= 900 MW * 1.15) . Thus 115 MW (= 1150 MW – 1035 MW) is the reduction in the LSE's RAR due to the Load Modifying Resources DR, before any adjustment for avoided line losses.

Q.14. DOES SUPPLY RESOURCE DR HELP MEET A LSE'S RAR?

A.14. Yes. While a LSE does not include Supply Resource DR in its net load forecast, it counts Supply Resource DR to meet its RAR on a one-for-one basis. In the above example, a 100-MW Supply Resource DR contributes 100 MW to the LSE's RAR.

Q.15. IS LOAD MODIFYING RESOURCE DR SIMILAR TO SUPPLY RESOURCE DR IN MEETING A LSE'S LOAD OBLIGATION?

A.15. Yes, as demonstrated in the above example in A.13 and A.14.

IMPACTS OF LOAD MODIFYING RESOURCE DR ON WHOLESALE ELECTRICITY MARKET PRICES

Q.16. CAN LOAD MODIFYING RESOURCE DR AFFECT MARKET PRICES EVEN IF THEY ARE NOT FORMALLY OFFERED INTO AN ELECTRICITY MARKET AS SUPPLY RESOURCE DR?

A.16. Yes, as illustrated by the examples below:

- A LSE can reflect the impacts of a Load Modifying Resource DR program in its net load forecast. A lower net load forecast leads to the dispatch of a smaller quantity of supply-side resources by the ISO, which in turn reduces market prices.
- The LSE's notification to the CAISO of the planned activation of Load Modifying Resource DR should enable the CAISO to reduce its load forecast and alter its dispatch decisions accordingly. It is my understanding that PG&E provides such notification to CAISO through the *Daily DR Report*, as described in the *CAISO Demand Response Resource User Guide, Guide to Participation in MRTU Release 1*, Version 3.0. In addition, the IOUs provide daily reports to the CAISO by 8:00 a.m. during the summer period, indicating any DR that will be dispatched that day as well as the remaining amount of available DR. Given that PG&E notifies the CAISO of the amount of DR it plans to dispatch as well as its location, there is sufficient time to enable the CAISO to use this information in its dispatch model.

- The price reduction due to DR may occur in the day-ahead market when the expected DR MW-reduction is included the CAISO's day-ahead price determination. It may occur in the real-time market when the actual DR MW-reduction becomes part of the CAISO's real-time price determination. On those rare occasions when the LSE is unable to provide advance notice of a curtailment, it may take a couple operating 5-minute intervals before the CAISO is able to recognize the effects of the curtailment in its dispatch decisions and real-time wholesale price formation.
- A dispatch of DR by a LSE will – even without any advance notification to the CAISO – be reflected in real-time generation levels and in dispatch decisions, albeit perhaps with some short time lag, because the actual DR MW-reduction would have been part of the LSE's actual real-time load.
- Even absent formal notification, the CAISO can, over time, learn how various events trigger deployments of Load Modifying Resource DR programs, as well as program participants' actions.

Q.17. PLEASE PROVIDE AN EXAMPLE OF MARKET DEMAND AND SUPPLY TO ILLUSTRATE THE PRICE REDUCTION EFFECT OF LOAD MODIFYING RESOURCE DR.

A.17. Consider Figure 1 that portrays a hypothetical electricity market's demand and supply for a particular hour. Numerical examples that refer to the specific quantities and prices shown in Figure 1 are presented below in A.19. The supply curve represents how additional resources become available to the electricity market as prices rise. Some supply-side resources cannot operate profitably if they receive low prices to compensate their operation. But, as prices rise, more resources will find it profitable to operate, as reflected in their bids to an ISO, such as the CAISO.

The demand curve has a downward slope, consistent with the expectation that as price increases, overall demand for a good or service declines. In the case of electricity markets, retail customers are represented by LSEs. As price increases, LSEs are less inclined to purchase supply from the CAISO market on behalf of their customers because: (a) they will anticipate some demand reduction from customers that are exposed to market price signals (e.g., customers that face real-time pricing); and (b) they may exercise measures to reduce load or use out-of-market generating resources to which they may have access.

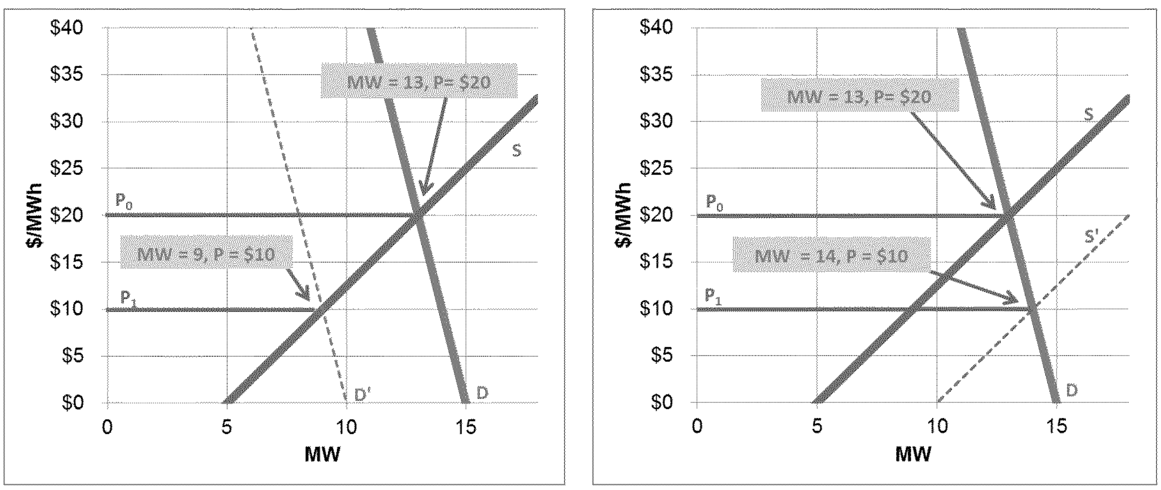

Figure 1. Hourly market demand and supply curves

In this example, both the demand and supply curves are "aggregates", representing the sum of all supply-side resources and total demand of all customer loads in the market. For expositional simplicity, this figure does not include line losses, which would gross up the load reductions from demand response after line losses to be equivalent to supply before line losses.

Figure 1 is merely designed to assist me in illustrating some concepts. The actual shapes of the curves are unlikely to be smooth straight lines in practice. An actual hourly supply curve "stacks up" the actual quantities and bid prices of resources bid into the market. It tends to look lumpy, reflecting large increments of generation. In practice, the hourly demand curve tends to be steep, suggesting limited price response even at relatively high market prices. Had the market demand been highly responsive to price changes, few DR programs would be needed to induce additional demand reduction, beyond what a market price increase could normally do. Despite these abstractions, I can illustrate some concepts with this simple graph.

Here, I am focusing on one region of the demand and supply curves. Absent any deployment of Load Modifying Resource DR, the market demand curve in Figure 1 is the downward sloping **blue** line labeled D. Thus, this curve does not account for the curtailable demand of participants in the DR program. The market supply curve is the upward sloping **red** line labeled S. The market-clearing price (MCP) is P_0 that equates the megawatt (MW) demanded and MW supplied for a given hour.

I now focus on a shift in the demand curve. Suppose there is a deployment of a Load Modifying Resource DR program under the assumption that the program is reliability-based (e.g., an interruptible load program with an up -front payment for the curtailable MW).[1] When included in the demand side, the deployment of the program reduces the MW demanded, yielding a new demand curve , which is the blue dashed line labeled D'. This new dem and curve is parallel to the original demand curve: for any given price, demand is reduced by the same MW quantity. This is achieved by shifting the demand curve to the left. The quantity of demand curtailed through the DR program is no longer in the mar ket, due to the deployment of the Load Modifying Resource DR program by a LSE. The lower level of demand allows an ISO to move down the supply curve, thus avoiding some higher -priced supply -side resources. This is the means through which Load Modifying Resource DR can lower market prices. The new MCP is P_1, which is less than P_0.

[1] Fig. 1 reflects a situation where the amount of DR is not affected by the market prices (at least those market prices which are reflected on the graph). This might reflect a reliability -based program or a situation where market prices depicted in the graph are all above the "strike price" at which participants in the DR program have agreed to curtail. In this situation, the demand or supply curves reflecting the DR are parallel to the demand or supply curves without DR. There are other situations where the amount of available DR increases as the market price increases. This might reflect a program involving multiple energy consumers with a variety of strike prices at which they would be willing to curtail their electricity use. In this situation, the c urves with and without DR may no longer be parallel to each other, at least in some ranges of prices and quantities.

Q.18. PLEASE DISCUSS THE PRICE REDUCTION EFFECT HAD THE LOAD MODIFYING RESOURCE D R IN FIGURE 1 BEEN C ONVERTED TO SUPPLY RESOURCE DR.

A.18. I now examine DR as a shift in the supply curve. Had the DR in Figure 1 been converted to Supply Resource DR and deployed by the ISO, it would shift the market supply curve to the right, yielding a new supply curve, the red dashed line labeled S'. As the DR amount is assumed to be the same as the one in **A.17** above, the new MCP is also P_1, which is less than P_0. Hence, in this example, making the Load Modifying Resource DR in Figure 1 into a Supply Resource DR does not lead to a larger price reduction.

Q.19. CAN YOU PROVIDE A NU MERICAL EXAMPLE TO DEMONSTRA TE DR'S PRICE REDUCTION EFFECTS?

A.19. Yes. My example assumes the following market demand and supply equations to represent the demand and supply curves in Figure 1:

- Market demand: $D = 15 - 0.1P$, which shows the MW demanded at the market price P. At $P = 0$, the MW demanded is 15 MW. For each \$1/MWH increase in P, the MW demanded declines by 0.1 MW.
- Market supply: $S = 5 + 0.4P$, which shows the MW supplied at the market price P. At $P = 0$, the MW supplied is 5 MW, so as to reflect must-run generation's output. For each \$1/MWH increase in P, the MW supplied rises by 0.4 MW.

The intersection of the demand and supply curves signifies market clearing: the MW demanded is equal to the MW supplied. Th e MCP is \$20/MWH and the market clearing quantity (MCQ) is **13** MW. I verify the **13**-MW MCQ by substituting the MCP of \$20/MWH in the market demand and supply equations, resulting in (a) ***D* = 13** = 15 – 0.1 * 20; and (b) ***S* = 13** = 5 + 0.4 * 20.

Now assume a quantity of DR of 5 MW that it is dispatched for reliability purposes. There are two cases to consider:

- Case 1: Load Modifying Resource DR. If the 5-MW DR were included in the demand side, the market demand equation would become:

  Market demand with DR: $D' = 15 - 0.1\,P - 5 = 10 - 0.1P$.

  The new MCP is \$10/MWH and the new MCQ is **9** MW. I verify the **9**-MW MCQ by substituting the MCP of \$10/MWH in the equations for the market demand with DR and the market supply without DR, resulting in (a) ***D'* = 9** = 10 – 0.1 * 10; and (b) ***S* = 9** = 5 + 0.4 * 10. Hence, the market consumption is **9** MW.

- Case 2: Supply Resource DR. If the 5 -MW DR were included in the supply side, the market supply equation would become:

  Market supply with DR: $S' = 5 + 0.4\,P + 5 = 10 + 0.4\,P$.

  The new MCP is \$10/MWH and the new MCQ is **14** MW. I verify the **14**-MW MCQ by substituting the MCP of \$10/MWH in the equations for the market demand without DR and the market supply with DR, resulting in (a) ***D* = 14** = 15 – 0.1 * 10; and (b) ***S* = 14** = 5 + 0.4 * 10 + 5. The market consumption is **9** MW (= 14 – 5) as in Case 1, since the DR-MW reduction is assumed to be 5 MW.

Q.20. WHAT CAN YOU CONCLUDE FROM YOUR EXAMPLE?

A.20. My conclusion is that a 5-MW DR's price reduction effect does not depend on whether the 5-MW DR is included in the demand side or supply side.

Q.21. YOUR PREVIOUS EXAMPLE ASSUMES THE DR WAS DISPATCHED FOR RELIABILITY REASONS. MANY DR PROGRAMS, HOWEVER, ARE DEPLOYED BASED ON WHOLESALE MARKET PRICES. HOW WOULD THAT ALTER YOUR ANALYSIS?

A.21. The above analysis also serves to illustrate the deployment of price responsive DR where the market price is above the "trigger point" for that DR. The economic decision for a DR participant is similar to that for a generator: is the market price sufficiently high to induce the DR participant to curtail its load? As will be shown below, the presence of price sensitive DR would complicate my analysis. However, it would not materially alter my conclusion that DR's price reduction effect is largely independent of whether the DR is included in the demand side or supply side.

I will first consider a situation where all of the DR is dispatched at the same strike price. I will also use supply and demand curves that are more "lumpy," reflecting how the large blocks of generation resources might affect the shape of the supply curve and how various demand-side resources dispatched at various price levels might affect the shape of the demand curve. Following this graphical example, I will provide an algebraic example where the curves are once again straight lines (to simplify the math), but the amount of DR in the market increases as the market price increases.

Q.22. WHAT IF THE LOAD MODIFYIN G RESOURCE DR PROGRA M IN FIGURE 1 IS DEPLOYED BASED ON MARKET PRICES?

A.22. Investigating the effect of DR that is deployed based on market prices requires Figure 2 that shows supply and demand curves with discrete bids, each of which has a specific quantity and price. Let's assume that all the DR in the program is dispatched based on the same trigger price. The first graph on the left shows the MCP without DR. The middle graph shows the effect of adding a price elastic Load Modifying Reso urce DR. I define this example as price elastic because a small increase in price (along the vertical axis) produces a proportionally larger MW reduction in demand (along the horizontal axis). For illustrative purposes only, imagine in this case that a $ 10/MWh increase in price causes 50 MW of Load Modifying Resource DR to be triggered for curtailment. The addition of price elastic Load Modifying Resource DR produces the new MCP, denoted P_s on the graph. The final graph on the right shows the result of including price inelastic Load Modifying Resource DR. The DR is price inelastic because a large increase in price produces a comparatively small MW reduction. In each of these graphs, the portion of the demand curve that is not moving (i.e., the portion below the price at which the deployment of the DR is triggered) is shown as a bold segment of the blue line. Again, for illustrative purposes, imagine in this case that a $50/MWh increase in price causes only 10 MW of

Load Modifying Resource DR to be triggered for curtailment. This final graph shows the result of including price inelastic Load Modifying Resource DR. In this case, the new MCP is P_i, which is higher than P_s.

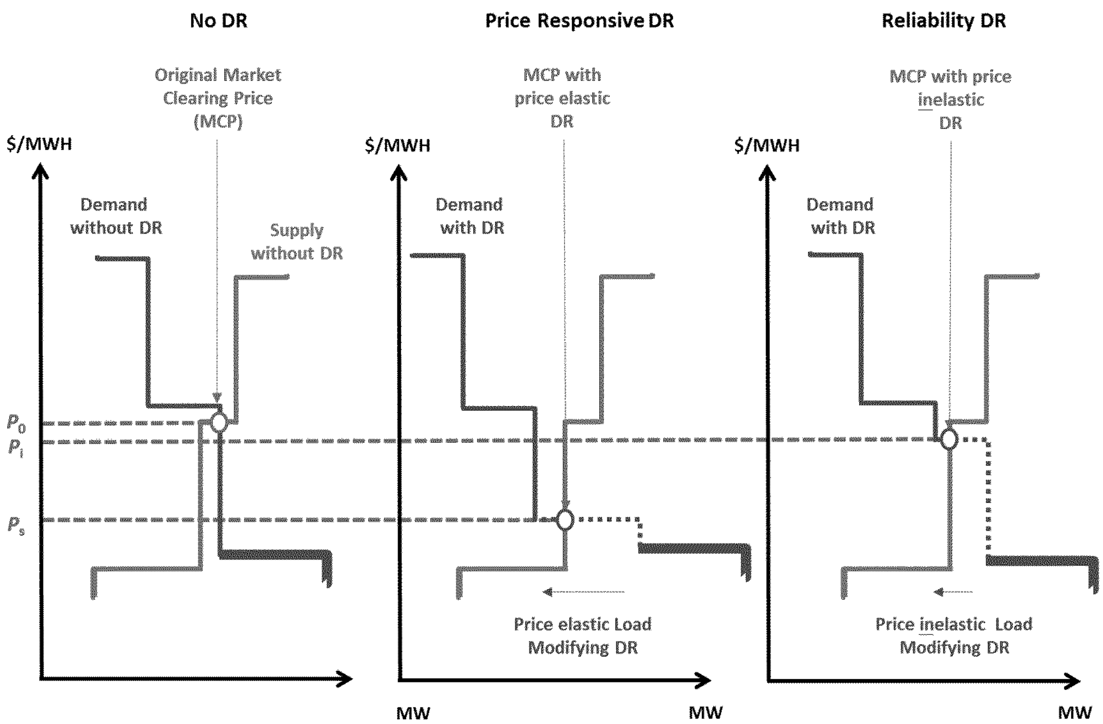

Figure 2. Hourly market demand curves with Load Modifying Resource DR

Q.23. WHAT IF THE LOAD MODIFYING RESOURCE DR PROGRAM IN FIGURE 2 IS CONVERTED INTO A SUPPLY RESOURCE DR?

A.23. Figure 3 shows the change in MCP when the DR is bid as supply. The first graph on the left shows the same MCP of P_0 from Figure 2.

The middle graph shows the addition of price elastic Supply Resource DR into the supply curve. The construct is exactly parallel to the one for Load Modifying

Resource DR in Figure 2, except that the price elastic DR now increases supply rather than reducing demand. Again the DR is labeled price elastic because a small increase in price produces a large increase in supply. The illustrative example would be the same as above: a $10/MWh increase in price causes 50 MW of Supply Resource DR to bid into and clear the market. The addition of price elastic Supply Resource DR results in the new MCP P_s, which is the same price as shown in Figure 2.

The final graph on the right shows the addition of price inelastic Supply Resource DR (e.g. a $50/MWh price increase yields only a 10 MW of Supply Resource DR). This results in the new MCP P_i, which is the same as the one in Figure 2 for Load Modifying Resource DR, and again higher than P_s.

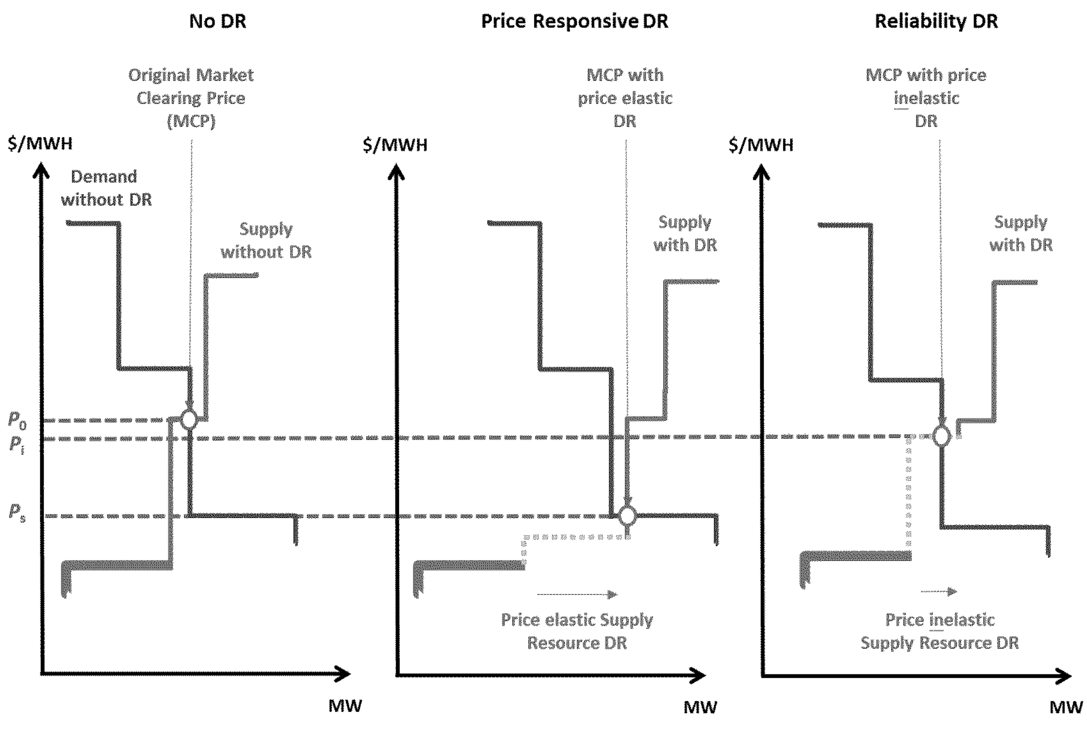

Figure 3. Hourly market supply curves with Supply Resource DR

Q.24. PLEASE PROVIDE A SIMPLE NUMERICAL EXAMPLE TO ILLUSTRATE YOUR ANSWERS IN CONNECTION TO FIGURES 2 AND 3 ABOVE.

A.24. This example modifies my prior example of linear demand and supply curves by allowing DR to be price sensitive.[2] For illustration, I assume the amount of Load Modifying Resource DR increases by 0.3 MW for each dollar increase in the market price, so long as the market price is above $10/MWH. Thus, the price sensitive DR program's MW reduction, as represented by *q*, is:

$$q = 0.3\,P \text{ for } P > \$10/\text{MWH}.$$

There are two cases to consider:

- Case 1: Load Modifying Resource DR . Here, I am using *D*" to designate the new demand equation. When the program is included in the demand side, the market demand equation would become:

$$D" = D - q = 15 - 0.1P - 0.3P = 15 - 0.4P.$$

Since the DR is included in the demand side , the market supply equation would remain to be:

$$S = 5 + 0.4P.$$

The MCP is $12.5/MWH, which is higher than the $10/MWH price needed to trigger the DR. I verify the MCP of $12.5/MWH by finding the MCQ of **10** MW: ***D*" = 10** = 15 – 0.4 * 12.5 and ***S* = 10** = 5 + 0.4 * 12.5. The DR MW-

[2] Although I would normally use the terms "price elasticity" and "price sensitivity" interchangeably, here I will use "price elastic" and "price inelastic" to refer to the relative amounts of the DR that can be achieved when a single trigger price for deploying a DR program is reached. I will use "price sensitivity" to refer to a situation where the amount of DR might increase as the market price increases.

reduction is 3.75 MW (= 0.3 * 12.5). Hence, the market consumption is **10** MW.

- Case 2: Supply Resource DR. Here, I am using *S*" to designate the new supply equation. When the program is included in the supply side, the market supply equation becomes:

$$S" = S + q = 5 + 0.4P + 0.3P = 5 + 0.7P.$$

Since the DR is included in the supply side, the market demand equation would remain to be:

$$D = 15 - 0.1P.$$

The MCP is $12.5/MWH, which is hig her than the $10/MWH price needed to trigger the DR. I verify the MCP of $12.5/MWH by finding the MCQ of **13.75** MW: ***D* = 13.75** = 15 – 0.1 * 12.5 and ***S*" = 13.75** = 5 + 0.7 * 12.5. The DR-MW reduction is 3.75 MW (= 0.3 * 12.5). The market consumption is **10** MW (= 13.75 – 3.75) as in Case 1, since the DR MW -reduction is found to be 3.75 MW.

Q.25. WHAT INFERENCES CAN YOU MAKE FROM THESE TWO EXAMPLES?

A.25. My inferences are as follow:

- The market clearing prices in both the graphical and numerical examples do not depend on how the DR is classified (Load Modifying Resource DR vs. Supply Resource DR), thus lending support to my view of comparable price reduction effects.

- There is no inherent benefit of transitioning Load Modifying Resource DR to Supply Resource DR unless doing so increases the price sensitivity or price elasticity of the resource.
- A resource will not increase the efficiency of economic dispatch if it does not respond to market prices or it only responds in a very limited fashion. To see this point, consider a Supply Resource DR program comprised only of very price inelastic or price insensitive DR. If the Supply Resource DR consistently bids at very high prices that are well above the MCP, no increase in dispatch efficiency is achieved because this Supply Resource DR is not used in meeting demand.

Q.26. WHAT IS THE IMPLICATION OF YOUR INFERENCES?

A.26. To increase economic efficiency, there must be some attribute of the Supply Resource DR that makes the same DR resource more price elastic or price sensitive than they would be when remaining in a Load Modifying Resource DR program. However, I do not see why a DR program could become much more price elastic or price sensitive, simply because the program is reclassified as Supply Resource DR, rather than Load Modifying Resource DR.

Q.27. PLEASE ILLUSTRATE HOW THESE RESULTS CAN INFORM COST-BENEFIT ANALYSIS FOR SUPPLY RESOURCE DR?

A.27. To demonstrate that Supply Resource DR is cost-effective from an IOU customer's perspective requires: (a) Supply Resource DR would need to have a greater impact on market prices or customer participation than Load Modifying

Resource DR; (b) a similar response cannot be achieved with Load Modifying Resource DR at an equal or lesser cost; (c) the realized savings would need to exceed the incremental cost of implementing the Supply Resource DR program; and (d) the Supply Resource DR implementation would not significantly stifle DR innovations that may occur otherwise under the Load Modifying Resource DR implementation.

Suppose a 100-MW of price-inelastic DR is included on the demand side. The resulting MCP is assumed to be P_i in the right graph in Figure 4. For simple illustration, I assume the Load Modifying Resource DR's price reduction is $1/MWH. Roughly 75 percent of load is self-scheduled, leaving about 5,000 MWs in Northern California exposed to NP15 prices during a peak hour with a 20,000 MW load. If a 100-MW Load Modifying Resource DR program is called 20 times a year for 4 hours each time (80 hours in total), the energy procurement cost saving is $400,000 (= $1/MWH * 5000 MW * 80 hours).

Now, consider an extreme hypothetical Supply Resource DR program that can achieve 3 times the $1/MWH market price impact, or $3/MWH, denoted as P_s in the left graph in Figure 4. This DR resource's procurement cost saving is $1.2 million (= $3/MWH * 5000 MW * 80 hours), which is $800,000 more than the $400,000 estimate for the Load Modifying Resource DR. The $800,000 reduction in procurement is the shaded green area in the left graph in Figure 4. I consider this example to be extreme, because it is unclear to me how a Supply Resource DR progam's impact could be so much greater than a Load Modifying Resource DR program.

To be cost -effective, the incremen tal cost of implementing 100 MW of Supply Resource DR would have to be less than $800,000 per year.

Q.28. HOW COULD A REQUIREM ENT TO BID INTO WHOL ESALE MARKETS AS SUPPLY RESOURCE DR STIFLE INNOVATION?

A.28. The challenges of meeting ISO requirements to participate in wholesale markets are addressed in the testimony of Dr. Alex Papalexopoulos (Appendix A) and Spence Gerber (Appendix B). I can, however, address this question more generally. ISO tariffs and market rules generally strive to make all types of resources meet a single product definition for each respective market. Product definitions are singular in their required response time (e.g. 10 minutes for spinning reserve) or duration o f delivery (e.g. minimum 4 hours of deliver for a capacity product). Product definitions and market rules in turn tend to evolve slowly over time, with lengthy stakeholder and approval processes. DR encompasses a wide diversity of customer times and end-use loads that may not fit neatly into a limited number of ISO product definitions. Furthermore, performance requirements may be difficult to meet for some loads creating a high risk of penalties.

Loads that vary in their availability, response time and duration cannot easily participate in specific ISO markets, but can nevertheless provide potentially valuable services to the grid. Loads that cannot meet strict requirements for Loads in SCED (in ERCOT) or Flexi-Ramp (in CAISO) could still provide valuable load following or flexibility services over a wider variety of time -frames or performance requirements. Load Modifying Resource DR has much greater flexibility in designing participation and performance requirements to accommodate different types of customers and loads. This can both provide greater freedom to experiment and innovate and facilitate higher levels of customer participation.

Q.29. WHAT IS YOUR CAVEAT FOR THE PRECEDING COST BENEFIT ANALYSIS?

A.29. My caveat is that I have assumed, for the sake of illustration, a similar increase in price responsiveness is not achievable for the Load Modifying Resource DR program. This is not necessarily true. There are many strategies and enabling technologies that can increase the price responsiveness of Load Modifying Resource DR, perhaps at less cost than transitioning the same resources to Supply Resource DR. Indeed, such strategies are employed for Load Modifying Resource DR in ERCOT. These include dynamic and real-time pricing signals and automated load control. Furthermore, these programs have the flexibility to reflect local distribution system conditions not visible to the ERCOT market.

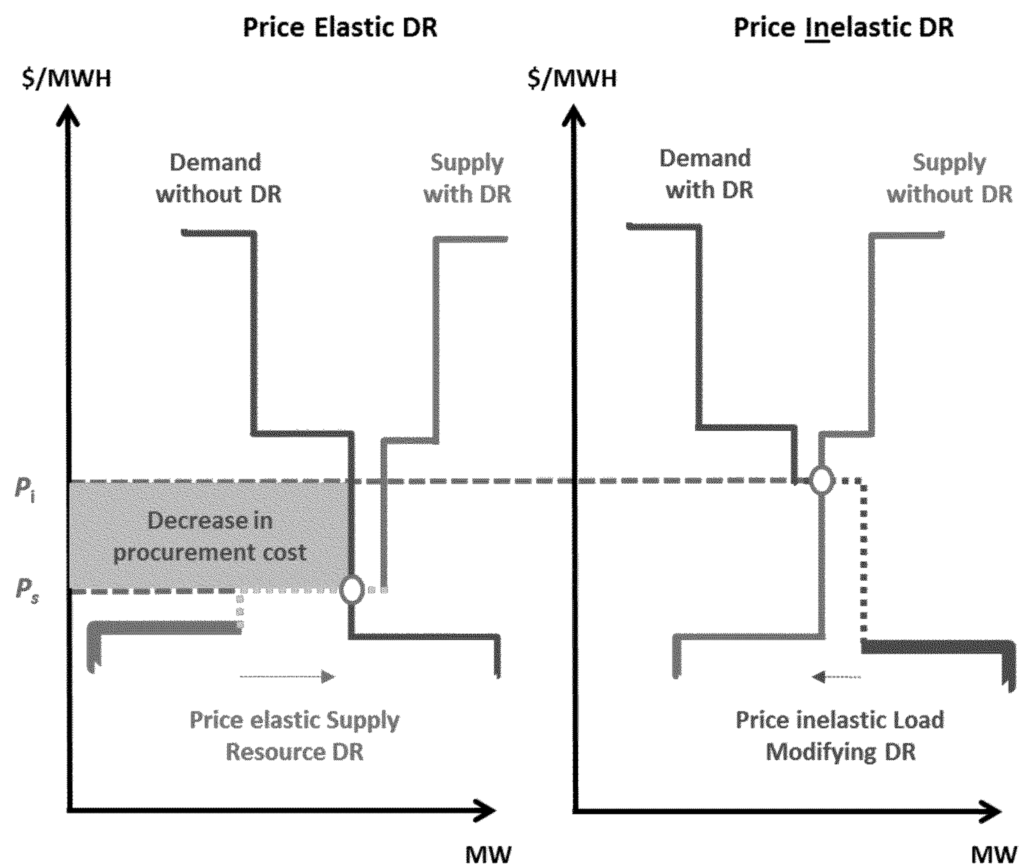

Figure 4. Decrease in procurement cost with lower MCP

Q.30. MAY LOAD MODIFYING RESOURCE DR HAVE OTHER BENEFICIAL EFFECTS ON THE OPERATION OF THE CALIFORNIA ENERGY MARKET?

A.30. In addition to lower market prices, both Load Modifying Resource DR and Supply Resource DR may assist utilities in managing local congestion on the distribution system and contribute to the reliable operation of the market. However, Supply Resource DR would likely have to be dispatched outside of the CAISO market to manage distribution-level congestion because these highly localized conditions are typically not reflected in the CAISO market.

THE COSTS AND BENEFITS OF FURTHER INTEGRATING LOAD MODIFYING RESOURCE DR INTO THE CAISO MARKET

Q.31. WOULD A REQUIREMENT THAT ALL OR MOST DR RESOURCES BE DISPATCHED BY THE CAISO LEAD TO A LOWER-COST OR MORE-EFFICIENT ELECTRICITY MARKET?

A.31. Not necessarily. A centralized dispatch of all resources does have some theoretical appeal – DR could affect price formation in a direct and formal manner and the CAISO could directly control the amount of resources dispatched to meet electrical demand. And it is possible that a LSE's forecast of future market prices or system conditions may have some inaccuracy, leading to some small inefficiencies.

However, the examples presented above demonstrate: (a) both Load Modifying Resource DR and Supply Resource DR can reduce procurement costs; and (b) it is the price elasticity or price sensitivity, not the type of the DR, that is the most important factor. And, as a practical matter, LSEs would seemingly have an incentive to accurately forecast future prices and system conditions in order to dispatch DR and reduce procurement costs efficiently.

Further, practical considerations suggest that it is not beneficial to require all or most Load Modifying Resource DR to be centrally dispatched by the CAISO, as explored in the testimony of other PG&E witnesses.

Q.32. WHAT ARE THESE PRACTICAL CONSIDERATIONS?

A.32. These practical considerations include the high transactions costs associated with DR being bid into and directly dispatched through the CAISO market.

Q.33. PLEASE EXPLAIN THE FIRST CONSIDERATION OF HIGH TRANSACTION COSTS.

A.33. Supply Resource DR bidding into the CAISO market must meet certain CAISO operational requirements. Because it is not bid into the CAISO market, Load Modifying Resource DR is not subject to these requirements. Examples of these requirements may include registration, telemetry, automated dispatch requirements, and special settlement and metering requirements, as explained in greater details by other PG&E witnesses.

Telemetry and metering are a required and relatively small cost for generators to serve their primary purpose of providing capacity, energy and ancillary services. In contrast, metering and telemetry requirements for DR participants can be significant relative to their DR-related potential revenues and bill savings. Finally, as noted in other PG&E witnesses' testimony, the registration process for Supply Resource DR is complex and lengthy, whereas the registration process for Load Modifying Resource DR can be much simpler. Such additional costs may exceed the benefits (if any) realized by an energy consumer from participating in a Supply Resource DR program instead of a Load Modifying Resource DR program.

Q.34. HAVE YOU SOUGHT TO QUANTIFY THESE COSTS?

A.34. No. However, many of these costs are further described and estimated in the testimony of other PG&E witnesses.

Q.35. WHAT MAY BE THE CONSEQUENCE OF HIGH TRANSACTIONS COSTS?

A.35. Based on my experience in Texas, requiring an existing Load Modifying Resource DR program to be bid as Supply Resource DR could discourage participation in DR programs and inhibit innovation in new DR products and technologies. While the economic gains due to new DR approaches are hard to quantify, they are potentially large because new energy management technologies are rapidly growing and the mass market for DR is in an early state of development.

It is also unclear whether a DR resource would be used or dispatched any differently if it was bid into the CAISO market. LSEs with the ability to dispatch Load Modifying Resource DR are sophisticated participants in the electric market so they would look to dispatch the Load Modifying Resource DR when it produces the greatest economic benefits. These LSEs closely monitor wholesale energy prices, and procure and dispatch resources to best meet the needs of their load in the most economically efficient way. Thus there may be little difference between the LSE's and the ISO's DR operation.

In short, requiring participants in Load Modifying Resource DR programs to become Supply Resource DR would likely reduce program participation without any appreciable additional benefit.

Q.36. IN SUMMARY, HOW DOES THE INCREMENTAL BENEFIT OF DISPATCHING DR IN THE CAISO MARKET AS SUPPLY COMPARE TO DISPATCHING THE SAME DR AS LOAD?

A.36. The incremental benefit is likely none or small because: (a) the market price impact of Load Modifying Resource DR is comparable to that of Supply Resource DR; (b) the potential MWH reduction by DR participants is small, as DR is generally called only few hours per year; and (c) the high transaction costs associated with Supply Resource DR that do not apply to Load Modifying Resource DR.

Q.37. HAVE OTHER MARKETS ADDRESSED SIMILAR ISSUES REGARDING THE DEGREE TO WHICH DR SHOULD BE DISPATCHED BY AN ISO?

A.37. Yes. The Electric Reliability Council of Texas (ERCOT) market has been grappling with this same issue in recent years. In ERCOT, many LSEs operate DR programs which are not formally dispatched by the ISO. Such programs may include direct load control programs, real-time pricing programs, and block and index pricing offered by retail electric providers, municipal utility systems, and rural electric cooperatives. Meanwhile, the ERCOT ISO is seeking to improve opportunities for loads to directly participate in ERCOT's real-time energy market through its "Loads in SCED" (i.e., loads in the security-constrained economic dispatch model) project. Direct participation in the energy market on this basis, however, will be voluntary. Hence, many DR programs will continue to operate outside of ERCOT's formal energy market because (a) the value of these out-of-market programs is recognized, and (b) many loads and programs would have difficulty meeting the ERCOT ISO's performance standards and metering and communications requirements. Further, many LSEs can realize benefits from dispatching such programs outside the events in which ERCOT would dispatch such resources. Finally, the ERCOT ISO has the ability to deploy certain out -of-market DR programs (e.g., those administered by transmission and distribution utilities as a component of their energy efficiency program portfolios) for reliability reasons under certain conditions . This degree of integration and coordination is considered to be sufficient and has worked well in practice.

Q.38. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A.38. Yes.

ATTACHMENT JZ-A

LIST OF PAPERS AUTHORED OR COAUTHORED BY JAY ZARNIKAU ON TOPICS

RELATED TO ENERGY MARKET STRUCTURE AND DEMAND RESPONSE

Refereed Journals:

“Did the introduction of a nodal market structure impact wholesale electricity prices in the Texas (ERCOT) market?” *Journal of Regulatory Economics*. Vol. 45(2), 2014. With C.K. Woo and Ross Baldick.

“The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest.” *IEEE Transactions on Power Systems,* 2013. With C.K. Woo, Ira Horowitz, Jonathan Kadish, and Jianhui Wang.

“The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market." *Utilities Policy*. 2013. With Dan Thal.

“Transparency of Retail Energy Pricing: Evidence from the U.S. Natural Gas Industry.” *Managerial and Decision Economics*. 2012. With C.K. Woo, Ira Horowitz, and Alice Shiu.

“The Many Factors that Affect the Success of Regulatory Mechanisms Designed to Foster Energy Efficiency,” *Energy Efficiency*. Vol. 5, No. 3, 2012, pp. 393-410.

“Blowing in the Wind: Vanishing Payoffs of a Tolling Agreement for Natural Gas-Fired Generation of Electricity in Texas,” *The Energy Journal*, 2012, Vol. 33(1), with C.K. Woo, Ira Horowitz, Brian Horii, and Ren Orans.

“Wind Generation and Zonal-Market Price Divergence: Evidence from Texas,” *Energy Policy*, Vol. 39(7), 2011, pp. 3928-3938. With C.K. Woo, J. Moore, and I. Horowitz.

“Successful Renewable Energy Development in a Competitive Electricity Market: A Texas Case Study,” *Energy Policy*, Vol. 39(7), 2011, pp. 3906-3913.

“Demand Participation in the Restructured Electric Reliability Council of Texas Market,” *Energy - the International Journal*. 2009.

“Did the Expiration of Retail Price Caps Affected Competitive Electricity Prices in Texas?,” *Energy Policy*, Vol. 37(5), pp. 1713-1717, 2009; with Linhong Kang.

“Aggregate Consumer Response to Wholesale Prices in the Restructured Texas Electricity Market,” *Energy Economics*. Vol. 30(4), pp. 1798-1808, 2008. With Ian Hallett.

"Industrial Energy Consumer Response to Wholesale Prices in the Restructured Texas Electricity Market," with Greg Landreth, Ian Hallett, and Subal Kumbhakar. *Energy - the International Journal*. 2007.

"Trends in Prices to Commercial Energy Consumers in the Competitive Texas Electricity Market," *Energy Policy*. Vol. 35(8), 2007, pp. 4332 -4339. With Marilyn Fox and Paul Smolen.

"Has Electric Utility Restructuring Led to Lower Electricity Prices for Residential Consumers in Texas?" *Energy Policy*, Vol. 34(15), pp. 2191-2200. With Doug Whitworth.

"A Review of Efforts to Restructure Texas' Electricity Market," *Energy Policy*, Vol. 33(1), 2005, pp. 15-25.

"Consumer Demand for 'Green Power' and Energy Efficiency," *Energy Policy*, Vol. 31(15), 2003, pp. 1661-1672.

"Advanced Pricing in Electrical Systems: Theory," *IEEE Trans. on Power Systems*, 1995; with Martin Baughman and Shams Siddiqi.

"Advanced Pricing in Electrical Systems: Applications," *IEEE Trans. on Power Systems*, 1995; with Martin Baughman and Shams Siddiqi.

"Integrating Transmission into IRP: Theory," *IEEE Trans. on Power Systems*, 1998; with Martin Baughman and Shams Siddiqi.

"Integrating Transmission into IRP: Applications ," *IEEE Trans. on Power Systems*, 1998; with Martin Baughman and Shams Siddiqi.

"Customer Responsiveness to Real-Time Pricing of Electricity," *The Energy Journal*, December 1990, Vol. 11, No. 4.

"Spot Market Pricing of Electricity," *Forum for Applied Research and Public Policy*, Winter 1990, Vol. 5, No. 4; with Martin Baughman and George Mentrup.

Under Review:

"Electricity-market price and nuclear power plant shutdown: Evidence from California." With C.K. Woo, Tony Ho, Arne Olson, Ryan Jones, Michele Chait, Ira Horowitz, and Jianhui Wang; revised and resubmitted to *Energy Policy*.

Non-Refereed Journals and Widely-Accessible Proceedings:

"Three Simple Steps to Clip the Peak in the Texas (ERCOT) Electricity Market. USAEE Working Paper No. 13-143. http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2334001

"Will the SIEPAC Transmission Project Lead to a Vibrant Electricity Market in Central America?," *Energy Forum*, 4th Quarter 2013. With Ian Partridge, John Dinning, and Daniel Robles.

"Texas Electricity Market: Best Gets Better," in *Evolution of Global Electricity Markets*, ed. Fereidoon Sioshansi, Elsevier. 2013. With Parviz Adib and Ross Baldick.

"Will Electricity Market Reform Likely Reduce Retail Rates?," *The Electricity Journal*, Vol. 22(2), 2009, pp. 40-45. With C.K. Woo.

Barriers and Policy Solutions to Energy Efficiency as a Carbon Emissions Reduction Strategy," in *Electricity Generation in a Carbon-Constrained World*, edited by F. P. Sioshansi, Elsevier, 2009. With Bill Prindle and Erica Allis.

"Integrating Demand Response into Restructured Wholesale Markets," in *Competitive Electricity Markets: Design, Implementation, and Performance*, edited by F. P. Sioshansi, Elsevier, 2008.

"The Quest for Competitive Electricity Markets," *LBJ Journal of Public Affairs*, 2008.

"Texas: The Most Robust Restructured Electricity Market in North America," in *Electricity Market Reform: An International Perspective*, Ed. F. P. Sioshansi and Wolfgang Pfaffenberger, Elsevier, 2007.

"Using Demand Response Programs to Provide Operating Reserves in Wholesale Power Markets: A Case Study of the ERCOT Market," *US Energy Association's Dialogue*, 2006.

"Taking Advantage of Real-Time Pricing Programs to Reduce Energy Costs in Manufacturing," *ACEEE Summer Study on Energy Efficiency in Industry Proceedings*, August 1997.

"Rewired for Competition: The Restructuring of Electricity Markets in Texas?" *Texas Business Review*, 1999.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX D

DEMAND RESPONSE COST EFFECTIVENESS,

POST-WORKSHOP QUESTIONS

PACIFIC GAS AND ELECTRIC COMPANY

Response to Energy Division Cost-Effectiveness Protocol Questions

3/15/2013

Background

Ordering Paragraph 7 of D.12-04-045 required that Commission staff hold one or more workshops to address all deficiencies of the 2010 Demand Response Cost-Effectiveness Protocols. The specific deficiencies identified in D.12-04-045 include:

- Inconsistency among the utilities' allocation of support program budgets such as ME&O, EM&V, and IT to each DR program
- Lack of definition of the DR "portfolio"
- Inconsistency among the utilities' calculation of the five adjustment factors (i.e., A, B, C, D, and E factors), particularly the A factor
- Utilities' analysis of "optional" costs and benefits

In accordance with D.12-04-045, on October 19, 2012, Energy Division staff held a workshop to discuss the deficiencies in the DR Cost-Effectiveness Protocols. The deficiencies identified in D.12-04-045 were included as topics 1, 2, 3, and 6, respectively, in the workshop agenda. Additional topics discussed include how to account for dual participation and participant costs in the DR cost-effectiveness framework. The topics discussed at the workshop were:

Topic 1: External Budget Allocation

Topic 2: Portfolio vs. Program Analysis

Topic 3: Avoided Cost Adjustment Factors

Topic 4: Dual Participation

Topic 5: Participant Costs

Topic 6: Optional Benefits

During the workshop, participants agreed that optional costs and benefits were not an issue unique to DR and should be addressed in the context of the broader demand-side cost-effectiveness framework, which is being considered in R.09-11-014. All other topics required additional discussion and clarification to help determine what modifications to the DR Cost-Effectiveness Protocols are necessary.

Specific Questions to be Addressed in Comments

Below are questions to which parties are invited to respond. These questions are based on the discussion questions posed by Commission staff at the October 20, 2012 workshop, but also include various comments and proposals made by workshop attendees. Parties may provide general responses to any of the questions, or specific response to any particular part of any question. Parties may answer some or all of the question, as they prefer. **However, utilities are required to respond to questions 11, 17, 19, 20, 38, 39, and 40.** Other parties may also respond to those questions if they choose.

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Although Permanent Load Shifting was not discussed at the October 2012 Demand Response cost-effectiveness workshop, we are including several questions here because of the need to develop cost-effectiveness methods which are specific to PLS. We encourage all parties who have been active in the development of the PLS program to respond to these questions

Topic 1: External Budget Allocation

Utilities are required to include all money related to Demand Response programs in their cost-effectiveness analysis of each program provided as part of any application seeking DR program funding. This includes money from Category 4, 6, 7 and 8 budgets in addition to the Category 1, 2, 3, or 10 program administration budgets. The cost-effectiveness analysis of each program may also include funds approved in other proceedings, such as incentives approved in General Rate Cases.

Budget Category #	Description
1	Reliability Programs
2	Price-Responsive Programs
3	Aggregator-Managed Programs
4	Emerging & Enabling Technologies
5	Pilots
6	Evaluation, Measurement & Verification
7	Marketing, Education & Outreach
8	DR System Support
9	Integrated Programs
10	Special Projects (e.g., PLS)

Currently, DR-related funds from other proceedings and Categories 4, 6, 7, and 8 are allocated to individual DR programs based on actual use by the program, or, if that cannot be determined, by allocating the budget proportionally to each program based on the total program costs. During the workshop, participants' opinions included that this allocation method did not reflect actual program costs, that any allocation method is arbitrary, and that we may be including more costs than we do on the supply side. Some participants contended that cost-effectiveness analysis at the portfolio level would eliminate the need to allocate many of these costs.

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Response to Energy Division Cost-Effectiveness Protocol Questions

3/15/2013

1. Assuming that we continue to allocate Category 4, 6, 7, and 8 budgets to each program, can this allocation method be improved? For example, it was mentioned that it may be possible to better estimate how much of the Category 6 (Evaluation, Measurement & Verification) budget is actually needed for each DR program. Are there other categories for which this may be true? For those budgets where it is impossible to determine actual program costs, are there allocation criteria other than total program budget that could make this process more precise?

   Response: Direct assignment of budgets is, of course, preferable. PG&E recommends that to the extent these costs (AutoDR, most of EM&V, and parts of ME&O and Systems Operations) can be directly attributed (i.e. directly benefits) to a DR program they are allocated to that program, but where they cannot be directly attributed to the program they should not be allocated to the programs. A more refined analysis of these costs to identify those that can be directly assigned should be done. DR costs that cannot be directly assigned to a program should be further categorized as applying to the overall DR portfolio for the purpose of a portfolio-specific cost-effectiveness analysis or to being costs that do not benefit the programs or portfolio. Costs that do not apply to either the DR programs or DR portfolio should be excluded from any DR cost-effectiveness analysis. No costs should be allocated to a DR program for the purposes of a program-specific cost-effectiveness analysis if they cannot be specifically attributed to that DR program. Some of the costs in these categories do not provide direct benefits to the DR program or portfolio. Instead they may have longer term benefits outside of the program cycle or if they meet a regulatory requirement or public policy objective.

   PG&E recommends evaluating cost-effectiveness on the DR portfolio rather than individual DR programs.

   This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

2. Which budgets from proceedings other than the three-year Demand Response budget proceeding should be included, and how should they be allocated? TURN proposed the inclusion of all DR-related IT costs from other proceedings; however, other parties argued that if a cost cannot be allocated to a program in a simple and clear manner it should not be included in the program's cost-effectiveness analysis.

   Response: When considering which costs to include, consider which costs would disappear if all DR programs were to disappear—i.e., DR programs include PLS but exclude mandatory dynamic pricing programs. Include such costs in the DR cost-effectiveness analysis and exclude all others. The principle here is that if a cost is sunk, mandatory or previously committed for other reasons, it should not be included in the DR

budget proceeding. Only incremental costs should be included in the DR budget proceeding.
This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

Topic 2: Portfolio versus Program Analysis

During the 2012-14 budget proceeding, it was difficult to determine the usefulness of the portfolio cost-effectiveness results since the definition of the demand response "portfolio" was not clear.

3. During the workshop, some parties proposed that any program dependent on funding should be considered to be part of the demand response portfolio. Others contend that dynamic pricing programs are actually rates and should not be considered part of the demand response portfolio or subject to cost-effectiveness. How should we define the demand response portfolio? Should dynamic pricing programs be considered to be part of the demand response portfolio?

   Response: Dynamic pricing programs and costs that support these programs should not be considered to be part of the DR portfolio for cost-effectiveness analysis in the DR budget proceeding. The DR portfolio should consist of only those programs which are funded or will be funded through the DR program funding mechanism in that application. However, there may be costs, which support both DR and dynamic rates that are requested in the DR proceeding because common systems or processes are used for both. The portion of those costs that can reasonably attributed to dynamic rates should not be included in any DR cost-effectiveness analysis.

   This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

4. In addition to dynamic pricing programs, there are other demand response programs that are approved outside of the three year budget cycles (e.g., aggregator contracts and other third party contracts such as SDG&E's AC cycling program). Should these programs be considered as part of the demand response portfolio?

   Response: No they should not be included in analysis of the portfolio cost-effectiveness. For instance, review of the winning AMP contracts already involves cost-effectiveness analysis of the contracts in the separate AMP proceeding. In A.12-09-004, et seq., that analysis required specific information about each individual contract. The Commission's decision to approve or not approve the individual AMP contracts takes that analysis into consideration. Thus, they should not be re-litigated in the DR budget proceeding. The *utility's administrative and support costs for AMP, however, are part of the DR budget proceeding and should only be reviewed from the perspective of whether they are "reasonable" costs to implement the program to the extent of Commission authorized activities.*

The basic principal is that approved budgets from other proceedings should be regarded as sunk costs that should not be included in the cost-effectiveness analysis of pending DR programs.

This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

5. Are there other demand response programs and activities which should (or should not) be included in the demand response portfolio? Why?

   Response: The DR portfolio for purposes of cost-effectiveness should only include costs that directly support the DR programs that will produce incremental DR MWs as a result of the DR budget being approved. Other costs that are related to DR should not be included in the DR portfolio for cost-effectiveness. This would include costs that may support DR program approved in other proceedings (e.g., Dynamic rates and AMP), cost for regulatory required activities (e.g. some EM&V, meeting PDR and RDRR requirements, etc.) and work for future DR programs (Emerging Technology, market design regulatory work, some ME&O, pilots, etc.).

6. If demand response programs or activities currently approved in proceedings other than the three year budget proceeding (e.g., dynamic pricing, AMP contracts, program incentives approved in the GRC) are determined to be part of the demand response portfolio, should they be procedurally moved to the three year budget proceeding?

   Response: No, there are many reasons why these proceedings have been addressed separately. There should not be an automatic procedural requirement to move them into the three year budget proceeding.

7. It was suggested at the workshop that cost-effectiveness analyses should be filed for **all** existing demand response programs in every three year budget application, whether or not funding for every one of those programs is being sought in the application. What are the pros and cons of providing this analysis?

   Response: Only the programs being funded based on the application, and those funded by the mechanisms approved in the Commission decision on the application, should be subject to cost-effectiveness evaluations included in the application. To do otherwise *would create undue complication and delay in the processing of applications and possibly adversely impact the funding and delivery of programs to customers.*

8. Assuming we can develop an acceptable definition of the demand response portfolio, how should the portfolio level cost-effectiveness analysis be used for decision-making? Should demand response programs be required to be cost-effective at both the program and portfolio levels? If so, should those requirements differ (i.e., should there be a cost-effectiveness standard for the portfolio and a different cost-effectiveness standard for programs)? What are the benefits to ratepayers of evaluating the cost-effectiveness of DR programs at the portfolio level?

   At the program level cost-effectiveness tests can be useful for information purposes and to help stakeholders gain insights regarding the drivers of low cost-effectiveness of programs. Each of the existing standard practice manual tests has a perspective that is useful and informative but no single test should determine whether a program should be included in the overall portfolio. In addition, cost-effectiveness is only one of the many factors for decision making as indicated in the Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo for the 2012 – 2014 DR Application on May 13, 2011.

   PG&E recommends the portfolio level should be the only binding cost-effectiveness test for the DR portfolio and that program level cost-effectiveness tests should be included in the application for informational purposes only. Since customers can move between programs and the value of certain program may change over time, the portfolio is the primary measure of DR value as it will allow changes in MWs across programs as customers migrate or as system needs dictate that certain program be focused on. The Commission should continue to view both the portfolio results and the individual program results. However, considering only the portfolio cost-effectiveness analysis allows more cost-effective DR programs to "subsidize" other less cost-effective DR programs, which can be a good thing. To the extent the latter DR programs are desirable to do for other reasons; this prevents the cost-effectiveness test from being a barrier to approval.

   This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

<u>Topic 3: Avoided Cost Adjustment Factors</u>

9. In comments submitted by the utilities on October 1, 2012 in R.09-11-014 regarding the broader, demand-side management cost-effectiveness framework, the utilities proposed the "R-power" estimate as a substitute for their relative loss of load expectation (LOLE)

models to show higher relative emphasis on the top net load hours than the current allocation based on the top 250 hours. Is the utility proposal a more accurate basis to use in calculating the A factor than the current model?

Response: To the extent that the current capacity allocation, based on the top 250 load hours, is a surrogate for relative loss of load expectation (LOLE), it can be improved by allocating capacity over those 250 hours in a manner that more closely approximates a LOLE distribution. Many of the parties at the workshop expressed their preferences for a methodology that embodied the basic principles included in a LOLE analysis. The "R-power" method was proposed as a "fallback" option if a transparent LOLP/LOLE method could not be developed in time for the 2015-17 DR application. It is better than the 250 hours, but not as good as a proper LOLP/LOLE method. The recently presented E3 calculator for LOLP looks like it may be able to be used for the 2015-17 application and assuming it "checks out" it should be the preferred way to compute the "A" factor.

This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

10. Would E3's proposal for a two-step A factor that accounts for availability and dispatchability in two components be an appropriate modification to improve the A factor? Would this modification be preferred over the utility proposal discussed above?

Response: E3's "two-step" A factor proposal appears to be a closer approximation of the principles embodied in an LOLE analysis and would be preferable over the existing model on those grounds. PG&E would be interested in studying and analyzing the methodology to gain a better understanding of the "two-step" approach before offering an opinion as to whether it is better than the utility proposal discussed above. A useful next step will be to have E3 set up the model so it can be "tested" by stakeholders to see how the results of this approach compare to the existing "A" factor approach of "250 Hours". This testing is needed to build confidence that the E3 LOLP model is working properly. E3 should produce some summary results for typical DR programs so that stakeholders can see the impacts of this approach.

This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

11. [Utilities are required to answer this question.] It was suggested at the workshop that many aspects of likely future demand response programs are not sufficiently captured in the avoided cost and adjustment factor framework, such as ramping ability, integration (into energy markets) value, quick response, etc. How should we fully value and account

for those values? Is there a need to modify the cost-effectiveness framework to include any of these values for the 2015-17 cycle, or should some or all of them be considered in future cycles?

Response: PG&E believes the values of many DR characteristics are not currently being captured in the avoided cost and adjustment factor framework. These include ramping ability, ability to bid into the wholesale market, quick response, effectiveness in reducing intraday ramping requirements, local dispatchability, ability to address over-generation of intermittent renewables, and deferral of specific transmission and distribution (T&D) projects. Because the IOUs must adhere to a cost-effectiveness standard for CPUC approval of their DR programs, the inability to reflect these benefits associated with these characteristics will hinder the develop of DR programs with these capabilities. To the extent that attributes such as ramping ability, wholesale market integration value, quick response, reducing ramping requirements, etc., can be valued in the CAISO market, the avoided cost and adjustment factor framework can be fine-tuned to capture them. Assigning value for deferred T&D projects is difficult to do on a prospective basis without knowing what projects can ultimately be deferred so the ED may want to consider a mechanism that allows for a case-specific cost-effectiveness test in these instances. Given the current time frame, it seems unlikely all of these attributes can be valued in time to be included in the 2015-17 application cycle. PG&E recommends that as an interim approach, the additional value from these added features can be considered as a "qualitative" benefit until such time as they can be quantified.

12. Is the value of local dispatchability captured within the existing avoided costs and adjustment factors? It was suggested at the workshop that while the T&D value was, in theory, being captured by the avoided T&D costs and the D factor, that locally-dispatchable DR has an additional local capacity value that is not currently being captured. For example, Resource Adequacy (RA) rules give local RA value only to programs which are dispatchable locally. Should the existing framework be modified to account for the full value of a locally dispatchable resource? For example, should we add another factor which would modify the avoided capacity costs to reflect the increased *capacity* value of programs which can be called locally? If so, how would that adjustment work? How should this adjustment be coordinated with the RA rules?

Response: A new adjustment factor for local dispatch by subLAP or LCA should not be added for the 2015-17 DR application. At this point there is no simple way in the cost-effectiveness methodology to include the local dispatch value from the CAISO markets of a locally dispatchable DR program and it will be very difficult to quantify such a value. Thus, PG&E recommends that at this time it may be best to include locational dispatch as a "qualitative" value for the 2015-2017 DR application as it related to locational value from the CAISO markets. As PG&E explained in its response to Q11, it is very difficult to determine a T&D value on a prospective basis. One potential way to address *this is to condition the implementation of a DR program capable of dispatch at the substation or lower level on the value of the T&D project being deferred. In other words, the DR program would not be implemented unless the value of the T&D project, combined with the other benefits of the DR program, equals or exceeds the program cost. Local dispatch does increase costs. Developing a consensus on some market value of local dispatch in time for the 2015-17 application is probably not a useful actively because there is so much uncertainty on the CAISO market as to how much local prices will vary.*

However, the CPUC must recognize that when a DR resource is located within a sub-Load Aggregation Point (subLAP) or Local Capacity Area (LCA), it is more expensive (on a per-MW basis) for a DR Provider (IOU or third-party) to provide a reliable amount of demand reduction. Because of the greater unit cost to deliver reliable demand reduction on a local basis, the incremental benefits should be included. Thus, if the CPUC wants to encourage the IOUs to provide more local dispatch (which has higher costs) for the 2015-17 application, the CPUC must assign a qualitative benefit to that program that justifies the cost of the local dispatch. In the longer term it may be possible to include a specific adjustment factor. In DR that can avoid explicit T&D costs should be assigned a value based on the actual T&D projects being deferred.

A different type of local value is addressed in the "D" factor in the cost-effectiveness protocols. The "D" factor addresses avoided T&D costs. This factor should remain. The incremental costs of such a granular level of dispatch should be offset by the avoided cost of the T&D projects being deferred. A forecast value of such local dispatch value can be submitted by the applicant and reviewed as part of the DR application litigation process.

13. Does the current framework fully capture the reliability aspects of demand response programs? For example, it was suggested that the value of demand response in responding to occasional large-scale transmission outages (which have been the cause of several demand response events in the past) is not valued in the current framework. If the protocols do not sufficiently capture the reliability value of DR to respond to events such as transmission outages, how can the framework be adjusted to capture this particular value?

Response: If DR is viewed as a Resource Adequacy resource the cost-effectiveness analysis already includes recognition of its system reliability benefits, regardless of whether there is a high peak load or transmission contingency, by attributing the benefit of avoided capacity costs to DR. Whether these are sufficient to gauge the benefits associated with transmission failure would seem to be better analyzed in the context of the local RA value issue addressed in question #12 above. In instances where DR is specifically established to address a local reliability need, as was ordered in Decision 13-02-015 in Track 1 of the Long-Term Procurement Plan proceeding, the reliability *value of the DR to respond to the specified local contingency must be reflected in the cost-effectiveness evaluation.*

14. Are there any other modifications needed to improve the accuracy and consistency of the avoided cost adjustment factors?

    Response: Improvement of the A factor is needed as was described in #9 and #10, above.

15. Currently, the B factor, which adjusts the avoided capacity value based on program notification time, is 100% for day-of programs and 88% for day-ahead programs. Should the B factor analysis be more granular? In other words, should we develop values that distinguish between programs with notification times of 15 minute, 1 hour, 3 hours, etc.? If so, how should we determine these values? Should they be related to the CAISO's requirements for ancillary services?

    Response: No additional adjustments for notification time should be made for the 2015-17 DR application evaluation. Such assignment of value is not now used, even for generation resource evaluation. For the 2015-17 DR program application, PG&E recommends that an additional level of fast response be assigned a qualitative benefit. In the future, a more exact value may be assigned once the CAISO and CPUC finalize flexible capacity rules and value.

    As in locational dispatch, DR that is capable of quick response is more costly to implement than simple day-ahead DR. If the value of quick response is not reflected in the cost-effectiveness methodology, it will be difficult for the IOUs to develop such programs given the low likelihood that they would comply with the required benefit-cost ratio. Given that the CAISO has placed a high value on fast-response DR to address local and system contingencies, the benefits of fast response should be reflected in the cost-benefit analysis via a qualitative factor. The notification times for ancillary services should be considered when determining what constitutes "quick response" because they generally reflect the response time needed to respond to possible reliability contingencies. The response times needed for flexible RA (once these are determined) should also be considered.

    This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

16. Currently, the C factor, which adjusts the avoided capacity value based on trigger flexibility, is valued by the utilities as 100% for all programs (except for several programs to which PG&E has assigned a 95% value). It has been suggested that the C factor does not accurately account for how demand response programs are actually

triggered by the utilities. Should the C factor consider actual utility practices as well as any trigger restrictions in the program tariffs, CAISO operating procedures (e.g., dispatch protocols) or any other protocols, in determining the C factor? How can the C factor be adjusted to reflect these other restrictions?

Response: The C factor is intended to be valued based on the trigger flexibility of the various DR programs. The trigger flexibility of a DR program depends on the trigger features that make it callable and not on the actual historical record of a program being called. A common C factor for all the IOUs to use for similar DR programs should be established, so that there are not different interpretations.

This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

17. [Utilities are required to answer this question.] Describe, in detail, the decision process used by your utility to call a demand response event. Who makes this decision? What criteria are used? How does this differ for the various DR programs?

Response: Under a system emergency, California Independent System Operations (CAISO) notifies PG&E System Dispatch to call a DR event. Outside of a system emergency, PG&E has established the DR Program Trigger Decision process for DR event decision. Below is a summary of the process:

DR Event Trigger Decision Process
There are three high level steps required for calling our DR programs:

1. *Set the criteria for calling the program*
2. *Collect real- and near-real-time inputs*
3. *Determine if any of the program criteria meet the established criteria for calling*

Inputs:
The most relevant inputs that determine if a program should be called include:

1. *The forecasted temperature for the next 3 days*
2. *The forecasted CAISO heat rate*
3. *The forecasted CAISO maximum load*
4. *The number of event calls in the past 3 days*

Criteria for calling the program:
Using these inputs, a set of criteria are established to determine the set points to call a program that take into account the criteria to be able to trigger the program and the

timing that would have the most impact to help the grid. Once it has been determined that a program has met the criteria required for calling an event, a PG&E Director makes the final decision to dispatch the program(s).

The criteria are program-specific to allow PG&E to tailor event calling per the design and requirements of the program (for example, grid reliability v. peak shaving).

18. Because all programs are currently receiving close to the same value for the C factor, this metric has not proven to be very useful. The original intent of the C factor was to determine the extent to which barriers to or limits on each program's trigger were reducing its value to the grid. Would it be preferable to redefine the C factor to focus more on whether DR programs are callable, useful and/or visible to the CAISO? How could we measure this?

    Response: No, it is <u>not</u> preferable to redefine the C factor to focus on where DR programs are callable and/or visible to the CAISO. The current DR programs are useful to the CAISO. Though most of the DR programs reviewed are currently receiving close to the same value for the C factor, it is possible that new programs may be developed that have limitations on the programs, so the C factor would still be useful.

19. [Utilities are required to answer this question.] Describe, in detail, the methods used in the 2012-14 Demand Response application to determine the D factor for your utility's DR programs.

    Response: PG&E kept the D factor at the default level of zero percent as provided in the DR cost-effectiveness protocols. While PG&E is confident that targeted DR programs could have the ability to defer specific T&D capital projects, the analysis to support a quantitative estimate of the D factor was not sufficiently well developed to include such estimated impacts for the 2012-2014 program cycle basis.

20. [Utilities are required to answer this question.] The D factor is determined using "right time," "right place," "right certainty" criteria, but these criteria are not clearly defined. How could we better define them? Describe how these criteria are defined and used by your utility.

    Response: PG&E believes that all DR programs, due to their non-persistent nature, should all have a "zero" D factor unless they meet rigorous criteria for "right place", "right time" and "right certainty". The "right place" for DR to defer a T&D project depends on where an overload is forecasted to occur. For instance, if system planners have determined that a feeder is likely to become overloaded, the "right place" to target the DR is anywhere on that feeder. Similarly, if the overload is expected to occur on a substation level, then anywhere on that substation may constitute the "right place".

In some instances, DR meant to defer a specific T&D project will need to be dispatchable at granular level (e.g., substation or distribution feeder level) during a local peak period that may not be coincident with the system peak. The time when this local peak occurs constitutes the "right time" and can be determined by either aggregating customer meter data in the local area or by referring to the SCADA data for the targeted circuit(s).

In order to defer a specific T&D project, PG&E's system planners must be satisfied that the required demand reduction will show up when and where it is needed, with a level of certainty on par with the "wires-based" T&D project. This "right certainty" is necessary to ensure that reliability is preserved.

As defined by PG&E, these standards are determined on a case-by-case basis and are justifiably rigorous; looser standards could risk the reliability of PG&E's transmission and distribution system. However, these standards are difficult to apply on a generic, prospective basis. One way to address this problem would be to allow the IOUs to estimate how many specific T&D projects may be deferred. This estimate can then be used to develop a value for the D factor that can be used in the cost effectiveness calculation.

Topic 4: Dual Participation

The Load Impacts (LI) of demand response programs used for cost-effectiveness analysis are currently based on Resource Adequacy (RA) rules. This means that customers who are enrolled in two demand response programs are counted only in one of those programs. While this is necessary for RA purposes, it has been suggested that it is not necessary for cost-effectiveness purposes, and that because of this practice, we are not accurately valuing the cost-effectiveness of programs with dually-enrolled customers.

21. There was general consensus during the workshop that the cost-effectiveness analyses of demand response programs with dually-enrolled customers (e.g., BIP and DBP) should include the load impacts of the dually-participating customers. How should we properly value the cost-effectiveness of programs with dually enrolled customers? Some of the options are (using BIP and DBP as an example):

    - Require an additional analysis of BIP and DBP combined
    - Continue to require a separate analysis of both DBP and BIP, but include dually-enrolled customers in each analysis
    - Continue to require a separate analysis of both DBP and BIP, but also require a separate analysis of a combined BIP/DBP with just the dually-enrolled customers.

    Response: PG&E designs DR programs based on a cost-effective portfolio approach and urges the Commission not to evaluate the programs on an individual basis.

However, if the Commission insists on performing individual program cost-effectiveness then PG&E recommends use the first option. The second option would also acceptable to PG&E as it was the consensus of the DR workshop. The third option should not be used.
This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

22. If we change the way we do cost-effectiveness for programs with dually-enrolled customers, how can we be assured that we are not double-counting load impacts in the portfolio analysis?

    Response: By definition, analyzing BIP and DBP in combination cannot double-count DR portfolio load impacts because dual-enrolled portfolio MW are included only once in the cost-effectiveness analysis. In the second option the portfolio analysis would be the same as for the first option.

    This is one of the top priority questions that should be answered in time for a June 30, 2013 finalization of the cost-effectiveness protocol and template. This is needed to provide adequate lead time for the 2015-17 DR application.

Topic 5: Participant Costs

Participant costs (net of equipment costs) are defined in the demand response cost-effectiveness Protocols as the sum of value of service loss and transaction costs. Because we do not know how to measure value of service loss or transaction costs, we use 75% of the incentives paid to customers as a proxy value. There was general consensus during the workshop that the time and resources required to accurately define and quantify participant costs would likely not be worth the additional information. Instead, there was a recommendation to perform additional sensitivity analyses to determine what differences may result from changing participant costs. . However, while precisely defining this quantity is likely to be both difficult (if not impossible) and costly, it may be possible to improve our estimate without incurring any great expense.

23. If we continue to use a percentage of the incentives paid to customers as a proxy measurement for participant costs, is 75% a reasonable estimate? If not, what would be more reasonable, and why? For example, we know that the maximum value of participant costs is 100% of the incentive costs, since presumably customers would not participate if their costs were greater than their benefits. The minimum value is 0%. Different customers will experience different amounts of productivity loss, comfort loss, and transaction costs. If these different amounts are normally distributed between the two extremes of 0% and 100%, the average value is 50%. Should we, therefore, use 50%? Is there any reason to think that participant costs are *not* normally distributed (i.e.,

skewed towards either end of the scale)? Without any evidence that participant costs are skewed towards the higher end of the scale, can we justify continuing to use 75%?

Response: 75% of incentives is a reasonable surrogate for participant costs, compared to any other number, when such costs are not known. Sensitivity tests can be performed at lower or higher levels, e.g., 0%, 50% and 100% of incentives. It is reasonable to assume DR incentives are compensating all of a customer's costs plus something extra to cover the customer's "hassle" of participation. The current assumption is adequate.

24. Can we better estimate program-specific participant costs, at least for certain programs? For example, studies of customers enrolled in air conditioner (AC) cycling programs indicate that most of them do not notice that an event is occurring – in other words, they experience no loss of comfort or productivity. Since transaction costs for AC cycling program are likely minimal, this would indicate that participant's costs for AC cycling programs are much closer to zero than to one hundred percent of the incentives they are receiving.

    Response: In the case of PG&E's AC cycling program, a participant receives only a one-time, token incentive, akin to a good-faith gesture rather than to compensate the customer for any inconvenience due to installation of an AC switch or thermostat. If the customer must be present for this work, the customer is possibly not fully compensated for that waiting time. Such participant costs likely are low, but are not zero. However, in the case of programs like PLS where customers are installing equipment with a known cost range, it is more accurate to use the actual cost of the equipment.

25. It has been suggested that we could do a small, limited study of participant costs by surveying demand response program managers, aggregators, equipment vendors, and other people who have direct contact with demand response participants, to attempt to better estimate the value of service lost and transaction costs that participants perceive or experience. Would a limited study of this sort be useful? (A study of this type would be considered "limited" because it would not require customer surveying, could be completed in a few months, and would likely cost about as much as a typical process evaluation.)

    Response: Such a qualitative survey would be of limited usefulness at best. It is not recommended. Such imperfect results would invite challenge from parties perceiving the results as harmful or erroneous.

26. Another possible approach would be a small, limited study to determine whether better estimates of participants costs could be determined, using outage costs and technology costs as proxy measurements for value of service loss and transaction costs. For

example, there are studies of the cost of unplanned power outages[1] which determine the costs per hour, per kWh, and per peak kW that consumers experience during unplanned outages. Since DR participants have the ability (and receive incentives) to prepare for outages, it is a reasonable assumption that the costs of unplanned outages represent a maximum value for the service loss that DR participants might experience. Using the same logic, the cost of technologies (such as Auto DR) which automatically respond to DR events could be considered the maximum value of participants' transaction costs. For example, we can look at the choices that different customers who sign up for a DR make about investing in DR technologies. Some customers decide to purchase automatic controls, while others prefer to respond manually to events. Is it reasonable to assume that (1) the cost of the automatic controls is a reasonable proxy for the maximum value of the transaction costs associated with responding to DR events, since the customers who do not purchase the controls likely perceives that the cost of responding manually is *less* than the cost of automatic controls, and that (2) the cost of responding to DR events (whether manually or using automatic controls) represents most of the transaction costs associated with DR? Are these assumptions reasonable? Would a limited study of this sort be useful? ? (A study of this type would be considered "limited" for the same reasons as above.)

Response: We agree that DR incentive levels alone are insufficient to estimate DR participation costs as there can be many elements that contribute to DR participation costs and benefits. For example, some program incentive levels are deliberately designed to only pay a portion of the customer costs. In addition to incentive levels, customers may take other factors into account, including energy cost savings, demand charge savings, and certain less tangible benefits such as "looking green," when calculating the benefits of DR. However, how much each of these factors contributes to customer payback is highly customer specific, so it may not be accurate to use incentive levels alone as a proxy for participant costs (or some fixed percentage of participant costs) for all customers, without further investigation.

Only the customer can tell us what costs and benefits they took into account when deciding if/how to participate in DR and what capital expenditures to make. . A "limited study," as described in ED comments would be of limited value since customers, not vendors, utility program managers, or aggregators know best what costs and benefits they perceived and actually saw. There is no reason to ask groups that interact with customers when one can directly ask the customer.
Again, given the complexity of this topic, the 75% number plus sensitivity analysis should be used for the 2015-17 DR application.

[1] For example, *A Framework and Review of Customer Outage Costs,* LBNL 2003. http://certs.lbl.gov/pdf/54365.pdf

27. What additional kinds of sensitivity analyses should be performed for participant costs?

    Response: The standard sensitivity tests can be performed, e.g., evaluating participant costs at 50% or 150% of the assumed level in the cost-effectiveness analysis.

<u>Topic 6: Analysis of Optional Benefits</u>

Optional benefits identified in the 2010 Demand Response Cost-effectiveness Protocols include: environmental benefits (other than the avoided environmental costs for GHG), market and reliability benefits, and non-energy benefits. There was general agreement during the workshop that non-energy benefits are not a demand response-specific issue. As such, the identification of non-energy benefits, and the determination of their appropriateness for inclusion in the cost-effectiveness analysis, will be addressed in the larger context of the cost-effectiveness framework as it relates to all demand-side resources.

28. Are there any aspects of the optional benefits for DR, as described in the Demand Response Cost-effectiveness Protocols that should be discussed in this proceeding, or is it appropriate to discuss this topic only in the context of the larger demand-side cost-effectiveness framework?

    Response: The inclusion of optional (non-energy and/or monetary related) benefits should be discussed in the context of a larger demand-side cost-effectiveness framework. Certainly one reason, though not the only reason, for doing so would be to ensure that the various DSM programs are evaluated using a consistent set of criteria.

    Thus, this work will not be used in the 2015-17 DR application as there is insufficient time to complete it before the June 30 target to finalize the cost-effectiveness method.

29. Should we continue to allow consideration of optional benefits in existing tests, or should this be done only as part of a Societal Cost Test, as discussed in the June workshops on demand-side cost-effectiveness and the subsequent ruling?

    Response: Optional (non-energy and/or monetary related) benefits should be included only as part of a Societal Cost Test. Each of the various tests provides a different perspective of the cost-effectiveness of various DSM programs. Some are and should be focused exclusively on utility avoided costs and should not include the consideration of optional benefits that are not avoided by the utility.

    Qualitative benefits should be included in the 2015-17 DR application since there are several types of benefits (location, fast response, etc.) which will not be quantified.

<u>Additional Topic: Ex-post cost-effectiveness</u>:

30. It was suggested that ex-post cost-effectiveness analysis of demand response programs should be done as part of the evaluative process. Should we (or should we not) do this analysis? If we decide to do so, how should the cost and benefit inputs differ (i.e., which inputs would be the same as those used in our current ex ante analysis, and which inputs would be different)? For those inputs that should be different, how should we determine them? How should this ex post analysis be used by the Commission?

    Response: Ex-post cost-effectiveness analysis of DR is inappropriate. DR programs are intended to provide capacity to the market. The basis for determining the net qualifying capacity of DR programs is the 1-in-2 ex-ante conditions, as defined by the load impact protocols. The 1-in-2 conditions coincide with peak system conditions that would warrant a need for DR capacity. However, DR programs are frequently called outside of a monthly peak and should not be penalized for this. This would be akin to penalizing a generator's RA contract for providing less than its full NQC when market conditions do not warrant generation at full NQC. Analyzing DR CE on an ex-post basis would create a perverse incentive to only call the programs when system conditions are most extreme, thereby ensuring that the full NQC is achieved. This would unnecessarily limit the value of the resource.

    It is also important to note that up to three years of DR ex-post performance serves as the basis for determining the ex-ante load impacts. If the ex-post performance is poor, the ex-ante estimates will reflect that poor performance. Therefore, the ex-post results are effectively embedded in and ex-ante cost-effective analysis.

<u>Additional Topic: Lifecycle Analysis</u>

During the course of their research on Topic 1, TURN raised the issue of the assumed lifetime of various costs and benefits in the cost-effectiveness analysis of demand response programs. For demand response programs, all cost and benefit inputs other than capital costs are included for the three year budget cycle only. Capital costs are defined as any utility- or participant-funded costs incurred for demand response-related equipment (i.e., measure costs), as well as any equipment, software, or other investment costs incurred by the utility. Capital costs are amortized over the estimated lifetime of the investment, and the first three years (or fewer, depending on the start date of the investment) are included in the cost-effectiveness analysis. As a sensitivity, the entire capital cost is included in the three year analysis. This accounting method was adopted because parties felt that including all capital costs but only three years of benefits was a clear over-estimation. Furthermore, parties felt that the forecasts and assumptions that would have to be made to future costs and benefits over longer periods would be highly speculative.

TURN has pointed out that including only the first three years of these capital costs may result in under-estimating program costs. One proposed solution is to do lifecycle analysis (i.e., to include the costs and benefits over the entire effective useful lifetime of any capital costs related to the program), as is done for other energy efficiency programs. However, for energy efficiency programs, a one-time installation produces predictable savings over an assumed useful lifetime. This approach is not directly applicable to DR, which differs in three key respects.

1) DR requires continued active involvement by the customer and utility.
2) DR program rules, definitions and technology are constantly evolving.
3) DR programs can require a significant investment in enabling technology that can be stranded by low participation, customer turnover and technical obsolescence.

If the CPUC were to adopt a lifecycle analysis approach for DR, several critical issues would have to be resolved, as reflected in the following questions:

For the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

31. **Program evolution**. It is widely accepted that DR is in a transitional period, because of current efforts led by the CAISO to develop markets that DR resources can bid into, as well as the changing nature of both supply and demand due to RPS requirements. How does the nature of this transition affect our ability to do lifecycle analysis of DR programs?

    Response: Lifecycle DR cost-effectiveness analysis can be performed by making assumptions based on known information. A "transitional period" of one sort or another has almost always existed for DR programs. It does not impact our ability to perform lifecycle analysis. Any kind of life-cycle analysis must make assumptions about the future. To the extent that some of these assumptions are less certain, the building of scenarios can be performed to analyze the possible variations.

    However, for the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

32. **Future program costs.** Administrative and equipment costs have proven difficult to forecast with reasonable certainty even over just the three year program cycle. Can future costs and benefits be forecast with reasonable certainty past the three year program cycle, and if so for how long?

    Response: Assumptions past the three year program cycle will be uncertain, of course, but not unreasonable. Acknowledging that technologies can change, engineering estimates can, at least, provide our best understanding of future costs. As for administrative costs, since future program costs are likely a function of program participation, the future costs of a program with stable annual participation should have *stable annual costs. Businesses are constantly called upon to make decisions based on life-cycle analysis where costs and benefits are uncertain. DR programs, to the extent that they are programs to be valued over more than just a three-year cycle, should be no different.*

However, for the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

33. **DR impacts.** Can we estimate DR load impacts for periods longer than the next three year cycle accurately enough to provide reasonable results for cost-effectiveness analysis, and if so for how long?

    Response: DR load impacts are currently forecast for ten years in the annual load impact report submitted to the Commission every spring. These results are reliable for the given set of lifecycle assumptions.

34. **Capital costs.** Some DR programs incur capital costs and others don't. Is it reasonable to analyze DR programs with no capital costs over the three year cycle, and DR programs with capital costs over the lifetime of the investment, or should all programs be analyzed over the same number of years? If we analyze all DR programs over the same number of years, how do we determine that number, given the differing lifetimes of various investments?

    Response: It is reasonable to analyze different DR programs over different durations as long as the costs and benefits for each program are calculated over the same duration. It is difficult to speculate what program incentives will look like, what program enrollment will be, or if specific programs will even exist beyond the current program cycle. Therefore, it is not reasonable to extend the cost-effectiveness analysis for programs with little or no capital equipment investment beyond the current program cycle.

    However, it is reasonable to assume that customers that have invested in capital equipment are likely to use the equipment over its effective lifetime, even if there is no longer a program that directly incentivizes use of the installed equipment (such as PLS) or if the customer moves from one DR program to another (such as AutoDR). As a result, the costs and benefits of that equipment can be calculated over the duration of the equipment lifetime, even if that is longer than a program cycle.

However, for the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

35. **Customer costs.** Several DR programs consist of both customers who invest in equipment and customers who do not? Should these programs be analyzed over the lifetime of the equipment? What if only a small percentage of the program's customers have equipment investments?

    Response: This should not be a problem if the consideration is the cost-effectiveness for a particular DR program. The cost-effectiveness analysis is done using an average participant cost. It produces a mathematically correct result for the specific program.

    However, for the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

36. **Customer turnover.** How do we forecast customer turnover rates and stranded capital investment over the long term?

    Response: Consensus assumptions can be made for customer turnover rates and stranded capital investment, based on past experience of the IOUs.

37. **Alternative approaches.** If we decide that lifecycle analysis of DR programs is not possible, should we continue to use the current method of accounting for capital costs, as described above? If not, what alternate method of analysis should we use?

    Response: Lifecycle analysis of DR programs can be done. E3 has already created a tab in the DR Reporting Template to do lifecycle analysis (although currently it is only used for the PLS program). That new tab can be used for every DR program. There may be questions related to the uncertainty of the values for the various drivers of the cost-effectiveness analysis but the existence of uncertainty is characteristic of any forecast.

    However, for the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

TURN also pointed out that capital costs from preceding program cycles are not included in the cost-effectiveness analysis. Since the load impact estimates are the total load impact of each program, but the capital costs are incremental, there is a mismatch that overestimates the cost-effectiveness.

To solve this problem for those programs that are affected, either the program costs need to reflect the capital costs authorized in prior program cycles, or the load impacts must reflect only the incremental load impact. The workshop participants agreed that we must correct the problem, to the extent it exists, in one of two ways.

38. [Utilities are required to answer this question.] If we were to adopt an approach that compares the total load impact to all of the capital costs, including those from prior program years, we would need to determine: Is it feasible to track capital costs authorized in prior program cycles to determine the persistence of those costs in subsequent budget cycles? Would it be appropriate to evaluate the cost-effectiveness of the current program cycle by including capital costs that were already authorized and spent (i.e., sunk costs)? Should capital costs from prior program cycle years be included using the same amortization approach as is used for the current program cycle capital costs?

    Response: Yes, it is feasible to track capital costs authorized in prior program cycles and determine the persistence of those costs in subsequent budget cycles. "Sunk" costs, however, should never be included in a "looking-forward" cost-effectiveness analysis. Similarly, load impacts from existing customers should not be included in a "looking-forward" cost-effectiveness analysis if the program and load impacts will continue even if the DR budget is not approved.

    Capital costs authorized in prior program cycles are sunk costs in subsequent budget cycles and should not be included in the cost-effectiveness evaluation.

    However, for the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

39. [Utilities are required to answer this question.] If we were to adopt an incremental approach that compares the load impact attributable to the current program cycle with the current incremental capital costs, could the utilities readily estimate the incremental load impacts associated with the current program year?

    Response: This is a complex question that would require resolving a number of conceptual issues prior to answering the question. For example, how are incremental impacts defined for DR? Unlike energy efficiency, which provides persistent load reductions once a widget is installed, DR programs, excluding Permanent Load Shifting, would provide no load impacts if the program were not reauthorized in the coming cycle. Therefore, all DR MWs could be considered to be incremental. If that definition were adopted, the question is rendered moot. If a more restrictive definition is intended, that *needs to be defined. Would impacts from incremental customers be considered incremental? Would increased load impacts from existing customers be considered incremental? Some analysis would need to be done to determine whether incremental impacts, however they are defined, could be reliably forecasted for the purposes of CE. Since a number of foundational questions and issues need to be addressed before answering this question, it is not likely that this issue can be resolved in a timely fashion for the 2015-2017 application.*

However, for the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

40. [Utilities are required to answer this question.] Do you have a preference for which of the two approaches above we should pursue, or an alternative that does not require either of these approaches?

    Response: The method described in #38 above is the preferred approach.

    However, for the 2015-17 DR application there is not sufficient time to develop a consensus life cycle evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

<u>Additional Topic: Cost-effectiveness of the Permanent Load Shifting (PLS) Program</u>

Note: Although Permanent Load Shifting was *not* discussed at the October 2012 Demand Response cost-effectiveness workshop, we are including several questions here because of the need to develop cost-effectiveness methods which are specific to PLS. We encourage all parties who have been active in the development of the PLS program to respond to these questions.

Background

The primary test of cost-effectiveness used by the CPUC to determine the cost-effectiveness of demand-side programs is, traditionally, the Total Resource Cost (TRC) test. Some have argued that the TRC does not accurately measure the cost-effectiveness of programs with high participant costs. TRC costs consist of program administration costs and total equipment costs[2] (regardless of how those costs are shared by the utility and the participant). TRC benefits are the avoided costs of energy resulting from the installation of the PLS equipment, and are based on participants' energy and capacity savings. Programs with high equipment costs, therefore, tend to have relatively low TRC benefit/cost ratios. However, a large part of those equipment costs

[2] These equipment costs are often called "measure costs."

are paid by participants who are willing to bear the cost for reasons other than the resultant energy savings – in other words, participants accrue additional, "non-energy," benefits that may not be captured in the TRC benefits and costs. Hence, critics of the TRC claim it is a biased test (or applied incorrectly), in that it counts *all* the costs which participants incur, but not all the benefits.

In our calculation of energy efficiency (EE) cost-effectiveness, the CPUC remedies this supposed bias by removing both costs and benefits which were not caused by the EE measure from the cost-effectiveness calculation to create an "energy-only" TRC. We do this by using incremental measure costs and a net-to-gross calculation. Measure costs are simply the cost of the device that an energy efficiency measure is promoting. Incremental measure costs are limited to only the costs of the energy efficient portion of the device, as compared with a "baseline" device. For example, if an energy efficient refrigerator costs $800, but a less-efficient refrigerator with the same features costs $700, the incremental measure costs are $100. Using incremental measure costs insures that when we calculate the cost-effectiveness of the measure, we are including only those costs that the participant incurs to purchase an energy-efficient device, and not those costs which are incurred to provide energy end-uses, such as refrigeration or air conditioning. The net-to-gross calculation further limits the estimates of measure cost-effectiveness, by estimating the likelihood that the decision to buy the energy-efficient device was actually caused by the existence of the measure, rather than by external factors. Thus, only the costs and benefits of the "net" portion of participants is included. The remaining portion of the costs and benefits (i.e., the gross minus the net) is assumed to have occurred because of "free-ridership," which can be described as the likelihood that the purchase of the energy-efficient device would have been made even if the energy-efficiency measure did not exist.

Incremental measure costs and net-to-gross ratios are determined by studies which, although costly, are justified by the California's huge investment in Energy Efficiency programs (approximately $1 billion/year). For most types of demand response (DR), the total cost, rather than the incremental cost, associated with any purchases of DR-enabling technologies is included in the cost-effectiveness calculation, since the participant is not choosing among a myriad of products, each with a different level of efficiency, that are designed to provide specific, non-energy end-uses. Rather, the participant is purchasing a device with one purpose only – to reduce load. In addition, the concept of free-ridership does not pertain to Demand Response, since participants must actively choose to perform certain actions (or purchase equipment which will perform those actions) to receive DR incentives. Since DR does not provide benefits to the customer such as increased comfort or aesthetics, and does not often involve replacement of necessary devices, it is assumed that the type of non-energy benefits that the net-to-gross and incremental measure cost calculations are designed to "weed out" do not accrue to DR participants, at least not in any great amount.

However, the treatment of equipment costs for Permanent Load Shifting has to be somewhat different than for dispatchable DR, in that equipment purchases are necessary for all PLS participants, and the equipment provides more than one function. PLS equipment provides end-uses such as air conditioning as well as demand reductions, so we need to determine an incremental measure cost, as we do for EE devices, so as to be sure we are measuring only the cost of the demand reductions. This may also depend on whether the PLS installation is a retrofit or new construction. How, then, do we determine the incremental measure cost of PLS? For thermal energy storage devices, is the incremental measure cost the difference between the cost of the PLS system and a similarly-sized, traditional, air conditioning unit? Should the baseline air conditioning unit be an energy-efficient model or one that simply conforms to minimum efficiency standards? In addition, participants may be purchasing PLS systems for reasons other than providing demand reductions and air conditioning, such as a desire to be "green." This means that we need some sort of free-ridership estimate to determine the extent to which the availability of PLS rebates is "causing" participants to invest in PLS. How do we make that estimate?

The number of PLS systems is relatively tiny and the PLS program is quite new, so currently we have comparatively little data of this type. Hence, it is quite difficult to create an energy-only TRC for PLS at this point. Given these difficulties, we believe that the current TRC test does not provide a reasonable or useful estimate of the cost-effectiveness of the Permanent Load Shifting program, and have (as noted in D.12-04-045) relied instead on the PAC test.

Another difficulty with applying the current Demand Response cost-effectiveness framework as applied to PLS is in its treatment of avoided capacity costs. For dispatchable DR programs, the avoided cost of generation capacity is adjusted for each individual DR program, based on various program characteristics. The A Factor adjusts the avoided cost based on program availability (i.e., whether the program will be available when an event is called). The B and C Factors measure program notification time and the flexibility of the program trigger. Since PLS systems do not have to be triggered or notified, the B and C Factors for PLS have been set at 100%.

The A Factor for PLS has been the subject of much debate. Since PLS is not "called," as dispatchable DR is, the debate has focused on whether the PLS system is likely to be operating at times of peak capacity or other system need. However, this process – determining exactly when the PLS system is running, and for each hour it runs, how much less energy it is using than the system it replaced – is quite similar to the process used to determine the avoided costs of energy efficiency measures. For EE measures, we compare the total avoided costs for each hour[3] of the year with the measure's load shape. A load shape is the amount of energy savings the measure provides in each hour. It is *not* the same as an end use shape, which is the amount of energy *used* in each hour, although hourly end-use data is needed to determine a load shape. Since the pattern of hourly energy savings provided by PLS systems is quite similar to those provided by other of systems, such as energy efficient air conditioners, it may make more sense to determine

[3] While most measures look at hourly energy savings, some are aggregated only by month, or by time of use (TOU) period.

the avoided capacity costs of PLS using load shapes, rather than trying to calculate an A Factor for PLS.

Questions

41. Should the Commission continue to rely primarily on the PAC test, rather than the TRC test, to determine the cost-effectiveness of the PLS program, or should we instead attempt to develop a more accurate TRC test for PLS?

    Response: The Commission should rely on all four standard practice manual tests in making its decisions. Each test represents a different perspective and all are valuable. Viewing all four SPM tests is not mutually exclusive with developing accurate SPM tests, including TRC, RIM, PCT and PAC which should be done in any case. Attempts to develop a more accurate TRC test should be irrespective of which test is used to evaluate cost-effectiveness of the PLS program.

    However, for the 2015-17 DR application there is not sufficient time to develop a consensus evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

42. If we were to attempt to develop a more accurate TRC test for PLS, how could we determine the needed data, such as the incremental measure costs and a net-to-gross estimate? Is other data needed to develop a more accurate TRC, in addition the quantities discussed above?

    Response: We would require data based on past installations which can be used to develop incremental measure costs, i.e., the cost of the PLS system over and above the cost of a non-PLS HVAC system. But we must also keep in mind that the direction the new PLS program is heading during launch will make estimating/isolating the incremental costs difficult, even for those experienced with the projects and their modeling. The question is appropriate, but more discussion regarding the data needed, additional data needed, must be undertaken.

    However, for the 2015-17 DR application there is not sufficient time to develop a consensus evaluation method. Cost-effectiveness protocols and template are needed by the end of June 2013 so the current short term method should remain for that application.

43. Some of the parties in this proceeding have pointed out that thermal energy systems often replace old, inefficient air conditioners. How do we distinguish between the energy efficiency improvements and the increased enabling of demand-response that result from this type of installation, for cost-effectiveness purposes?

Response: We can start with an approach similar to that in the previous question, however, we must note that there is no clear cut methodology to adopt and we would need to dig into how much post and pre data we can collect. The important thing is to model the non-PLS HVAC system at the same efficiency as the PLS system. In this way, the "energy efficiency" load impacts are separated from the "demand response" load impacts.

44. Should the Commission continue to use the A, B, and C Factors to adjust the avoided generation capacity cost of the PLS programs?

    a. If so, what are the problems with the current methods of determining those factors, and how can we better estimate them?

       Response: Yes, the Commission should continue to use the A, B and C factors. There are no problems with using the current methods. The B and C factors can be correctly assumed to be 100%. E3 has already included tabs in the DR Reporting Template with which to calculate the A factor.

    b. If not, does the alternate method proposed above (i.e., using load shapes) seem reasonable, or would another method be preferable (please be specific)? How do we go about developing a PLS load shape(s)?

       Response: The alternate method proposed above is not necessary.

PACIFIC GAS AND ELEC TRIC COMPANY

APPENDIX E

DEMAND RESPONSE INTEGRATION OLIVINE REPORT

(REDACTED VERSION)

Olivine, Inc.

Evaluation of PG&E's Demand Response Programs for Wholesale Market Integration

Final Project Report

Olivine, Inc.
December 20, 2013

Contents

1 Executive Summary

Olivine has been engaged by PG&E to review and evaluate their existing Demand Response program portfolio for integration into the wholesale market as a supply side resource. PG&E has experience in wholesale market integration, bidding a previously active program, PeakChoice™ as a Proxy Demand Resource (PDR) into the CAISO Day-Ahead Energy market. As a result, PG&E is conscious of many of the complexities involved in aligning the program rules and operational procedures with the wholesale market requirements. The level of interdependencies and uncertainty as to a number of issues not only adds additional complexity to the integration itself but also to the evaluation process.

The analysis was performed using a two-part methodology because of these complexities and PG&E's desire to re-start bidding into the CAISO wholesale market in 2014. The initial assessment evaluated compatibility of each existing program with the wholesale market based on the current program and CAISO requirements to determine feasibility and provide focus. In the second part of the analysis, programs that were deemed to have a structure that could feasibly support integration were further evaluated based on defined criteria. The first portion of the analysis clearly indicated that to integrate most of the programs in their entirety would not be feasible due to the number of areas of misalignment and changes that were required. During this phase of the assessment portions of programs were considered to support a goal of integration, providing insights into the types of changes that would be required. In this phase, current enrollment characteristics and anticipated changes in processes or rules during 2014 were taken into consideration.

Specific criteria included:

1. Market Product Fit
2. Use Limits
3. Bidding Considerations
4. Dispatch and Notification Timing

The assessment resulted in a recommendation to include BIP, CBP and AMP in the development of an integration plan that could occur without tariff changes. BIP is proposed for integration as RDRR, once it is available at the CAISO while CBP Day Ahead and AMP Day Of products are proposed for PDR. Although this may sound counter-intuitive, the current award and notification processes for both of these products align with the CAISO Day Ahead market allowing for customer event notification to remain unchanged.

Olivine recommends that this initial integration occur during 2014 as a 'transition pilot' providing insights into the processes, issues, rule and infrastructure changes that will be required for a larger transition. This is not an isolated effort and will be most effective coordinating with broader activities such as R.13-09-011. We believe that it is critical to move forward quickly in order to have real world experience to inform broader policy and strategic decisions, but to do this cautiously to address underlying complexities and provide valuable lessons learned. We further recommend that the integration of all three (3) of the recommended targets for integration be included in this activity due to the number of critical considerations that could create a barrier for any one of them to be integrated successfully in the near-term.

Examples of these critical considerations are the timing of the implementation of RDRR by the CAISO, the timing of the implementation of Demand Response System APIs by the CAISO, the execution of agreements with LSE's for the inclusion of customers that do not receive Bundled Service and the validation of specific customer capabilities within identified Sub-LAPS.

This report includes an initial high level action with the recommended immediate first step to develop a more detailed integration plan to support some level of integration during 2014.

2 Report Objectives & Structure

The primary objective is to determine the feasibility for a path to CAISO market integration as a supply side resource of existing PG&E Demand Response programs. We identify programs or a portion of programs that are suited for integration starting as early as summer 2014. Since the issues involved are complex and interconnected, a two-phased methodology has been employed. First, the existing PG&E Demand Response retail program portfolio were reviewed and evaluated for compatibility with existing CAISO market models. For those programs deemed potentially compatible, further analysis will be conducted to assess challenges and issues involved in meeting CAISO requirements.

The report structure includes adequate background to provide the reader with an understanding of the current wholesale market situation and the complexity of integration considerations and variables. The report provides a high-level action plan. While this is not meant to be a detailed implementation plan, it is intended to serve as a roadmap for integration planning.

3 Situation Analysis

3.1 CAISO Markets

3.1.1 CAISO Market Roles

CAISO Demand Response direct participation requires the use of both a Demand Response Provider (DRP) and a Scheduling Coordinator (SC). The Utility Distribution Company (UDC) and Load Serving Entity (LSE) must also be engaged peripherally due to the resource registration process and market settlement.

A DRP is a CAISO legal entity that "owns" the load reduction resource and is responsible for maintaining the registration of the resource in the CAISO Demand Response System. Upon implementation of Rule 24, the DRP is also a legal entity with the California Public Utility Commission (CPUC) to the extent that the DRP represents CPUC jurisdictional load.

An SC is a CAISO legal entity and the only entity allowed to transact in the CAISO markets financially. All load and generation resources--including demand response resources--must be bid, scheduled, dispatched and settled financially with an SC. Proxy Demand Resources (PDR) and Reliability Demand Response Resources (RDRR) are Scheduling Coordinator Metered Entities and the SC representing such resources is responsible for submitting meter data to the CAISO.

The UDC is responsible for reviewing and validating its customers registered in a PDR/RDRR by a DRP into the CAISO Demand Response System (DRS). Validation includes determination of eligibility for inclusion in a resource, among other things. The UDC is generally the Meter Data Management Agent (MDMA), which requires providing Revenue Quality Meter Data (RQMD) to the DRP for translation to Settlement Quality Meter Data (SQMD). The DRP then sends the SQMD to its SC.

The LSE is responsible for reviewing and validating its customers registered in a PDR/RDRR by a DRP into the CAISO DRS. The CAISO requires that an LSE and DRP have a contractual relationship but provides no formal process by which to effectuate that relationship. Under certain circumstances the LSE's SC will also receive a meter adjustment (increase) on metered demand when PDR/RDRR energy settlement is priced below the Net Benefits Test (NBT) threshold price (See Section 3.1.6.1 below). Even in the absence of a meter adjustment related to DR priced below the NBT, the LSE's wholesale settlement reflects DR activity when metered demand is compared to bid-in demand, whether accounted for by the LSE demand bid or not.

In cases where PG&E is representing bundled customers in a PDR/RDRR, it could, but is not necessarily required to, serve as all four of the functions described in this section. There are several permutations of the relationship between three of these entities that would impose contractual implications. When Direct Access customers are a part of a PDR created from DR program participants, PG&E would retain the roles of UDC, DRP and DRP SC, but a third party would be the LSE. The CAISO requires that the DRP and LSE demonstrate that they have an agreement to facilitate this relationship. In the case where a third party is acting as the DRP for PG&E bundled customers, then PG&E would be the UDC, LSE and possibly the DRP's SC. In that scenario, the required CAISO agreement between the DRP (third party) and LSE (PG&E) would be necessary.

3.1.2 Overview of CAISO DR Resource Models

3.1.2.1 Proxy Demand Resource (PDR)

Proxy Demand Resources (PDR) are an aggregation of one or more locations (service accounts) within a single Sub-Load Aggregation Point (Sub-LAP) served by a single Load Serving Entity. The minimum amount of registered curtailable load is 100 kW. PDRs are eligible to participate in the CASIO market products Day-Ahead and Real-Time Energy as well as Non-Spinning ancillary services[1] if they meet additional requirements. Non-Spinning reserves require that a PDR be telemetered as well as any PDR 10 MW or larger. Additionally, a location (service account) can only be in one confirmed and active registration at any given time. The PDR model allows for a third party DRP to "own" the curtailable portion of the load while the LSE retains the obligation to bid/schedule the underlying load.

In the CAISO market software, the load curtailment of a PDR is modeled as generation, hence the moniker "Proxy." In the CAISO Master File[2], the minimum load of a PDR must be equal to or greater than zero and the maximum "generation" must be a positive value. Resource performance for energy is measured relative to a 10-in-10 baseline methodology that requires submittal of an aggregation of meter data from all of the locations in a registration.

During the initial setup of a PDR by a DRP, the CAISO assigns a unique resource identification. At the DRP's request, the resource ID is either modeled as a predefined location with a distribution across the Sub-LAP or as a custom location based on historic Demand data (provided by the DRP) for the specific network buses. Any change to the make-up of an aggregated PDR requires that the DRP update the registration by terminating the existing registration and establishing a non-concurrent start date for subsequent registrations. The CAISO registration process, whether initial or subsequent, allows 10 business days for both the UDC and LSE to review and comment on a registration. Following that, the CAISO has an additional 10 business days to approve a registration.

A PDR is bid or scheduled in the CAISO market using the assigned resource ID within the parameters documented in its Resource Data Template (RDT). Economic energy bids can be submitted hourly in 10 kW segments up to the maximum generation level indicated in the RDT using one to 10 separate price quantity pairs. A PDR certified for Non-Spinning reserves can submit a single price quantity pair per hour up to its certified Non-Spinning capacity quantity.

3.1.2.2 Reliability Demand Response Resource (RDRR):

Reliability Demand Response Resource (RDRR) is primarily for the use of scheduling Utility Emergency DR Programs directly in the CAISO market. RDRR is a result of a settlement between the CAISO, CPUC & IOUs ordered by D.10-06-034 on June 25, 2010 in R.07-01-041. In addition to limiting how large a percentage of emergency-triggered demand response resources in California made available under state retail demand response programs will be integrated into the CAISO's wholesale market design, the settlement also prescribed certain attributes that are assigned to RDRR to ensure visibility and dispatchability by the CAISO.

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[1] WECC is currently in the process of adopting standards that will allow spinning reserves to be provided by demand response resources but won't be in effect until 2015

[2] The Master File is a data repository at the CAISO including data that describes resource attributes.

Generally RDRR model composition and registration processes parallel PDR in terms of entity functions and time frames. RDRR can only participate in Day-Ahead and Real-Time energy although the Real-Time energy is only dispatched by the CAISO when a significant system emergency occurs. The Day-Ahead energy option is included to accommodate the high incidence of multiple program participation of enrollees in the IOU emergency programs such as Base Interruptible Program (BIP). To assure that RDRRs are only dispatched by the CAISO during system emergencies and reflect their high value, real-time energy bid prices must be at least 95% of the CAISO bid cap (i.e., 95% of $1,000/MWh).

Unlike PDR that requires telemetry for Non-Spinning reserves and all resources greater than 10 MW, there is no telemetry requirement for RDRR despite the fact that it is effectively an ancillary service contingency reserve. In recognition of some of the challenges related to metering RDRR, the CAISO allows DRPs to submit alternative measurement, using a statistical sampling of RDRR energy usage data rather than the default 10-in-10 baseline.

In addition to enabling RDRR to use the standard generation model, which is also the basis of the Proxy Demand Resource model, the CAISO requires the RDRR resources to elect either a marginal or discrete dispatch option. Under the discrete real-time dispatch option, there is only one bid segment and the CAISO must dispatch the entire cleared quantity of the resource.

3.1.2.3 Participating Load (PL):

Participating Load (PL) is a model that is most conducive to large transmission connected loads that can be scheduled by the LSE separate from all the LSE's other load aggregations. Any underlying load associated with PL is required to be scheduled in a Custom Load Aggregation Point (CLAP) by the same Scheduling Coordinator that schedules the PL resource. The PL model is a generation oriented resource and the underlying load is treated as negative generation. It requires direct metering from the resource and utilizes the full interconnection process to establish a resource. The outcome of these dynamics is that there is no third party option to schedule demand response, making it a generally poor fit for wholesale market integration.

3.1.2.4 Non-Generator Resource Dispatchable Demand Response (NGR-DDR):

Non-Generator Resource (NGR) model initially included the Dispatchable Demand Response (DDR) construct, conceived to expand demand response participation in ancillary services including frequency regulation. Due to functional flaws uncovered during the implementation phase, the DDR option was dropped from the NGR initial release and set aside for future redesign and release. NGR in general is largely similar to the PL model, which is not third-party friendly and has no workable method for DR metering. Further, use of NGR requires the full interconnection process under the Wholesale Distribution Access Tariff. While the CAISO has not completely abandoned the notion of reworking NGR DDR, it is not currently in any of the CAISO's externally published release planning activity through 2015.

3.1.3 CAISO Market Products

While models define the methodology by which resources interact with the grid, products are the services that the CAISO uses to operate the grid. Generally, the CAISO is agnostic as to which model provides a service, so long as it meets the criteria for a particular product. There are two categories of products, energy and ancillary services, that the CAISO procures in their markets and each category has sub products.

3.1.3.1 Day-Ahead Energy

Energy is procured in the Day-Ahead market in hourly blocks to meet the system-wide bid-in demand (LSE load) for each hour. Supply resources that clear each hour are paid a Day-Ahead Locational Marginal Price (LMP) that incorporates the system-wide marginal energy cost, locational congestion and the cost of transmission losses. The cost of energy procured is allocated to Utility Distribution Company Day-Ahead Load Aggregation Points (LAPs) which also have distinct LMPs. Energy bids (offers) are due by 10 AM one day prior to the operating day and treated distinctly for each hour. The CAISO strives to provide notice of awards by 1 PM one day prior to the operating day.

In the CAISO market optimization, both the price and quantity pair bid and any resource constraints are considered in the selection of a resource. To understand the impact that these constraints can impose, consider a resource with a minimum run-time of three hours. CAISO will not select that resource unless its bid is equal or less than the hourly LMP for three contiguous hours in order to respect the minimum run-time. There are also cases where the resource can be “constrained on” at minimum load to meet its minimum run-time if it is the best solution for a subset of the minimum run hours.

Day-Ahead awards are financially binding and paid at the Day-Ahead energy price with any imbalance (the difference between award quantity and calculated delivered quantity) settled as real-time energy.

3.1.3.2 Real-Time Energy

Real-Time energy is procured based on the CAISO system-wide short term forecast rather than bid-in demand. Real-Time energy bids are standing for each hour and can be submitted any time after the Day-Ahead market awards are published and up to 75 minutes prior to the start of an hour. Dispatches or awards occur in 5-minute increments, 2.5 minutes before each dispatch interval. CAISO Automatic Dispatch System (ADS) communicates notice of dispatch energy awards.

Real-Time energy settles in two different categories at 10-minute intervals, which are the combination of two 5-minute dispatch intervals. Dispatched energy settles as Instructed Imbalance Energy and paid at or above the resource bid. Deviation energy is settled as Uninstructed Imbalance Energy, which is based on the difference between awarded/dispatched energy and actual deliveries (baseline – actual meter). Positive deviations (actual deliveries greater than award/dispatch) are paid, while negative deviations (actual deliveries less than award/dispatch) are charged at the Real-Time price.

3.1.3.3 Ancillary Services (AS)

The CAISO procures 100% of its Ancillary Services (AS) requirements in the Day-Ahead market based on the CAISO forecast of system-wide demand. There are four distinct sub products of ancillary services, Upward Regulation, Downward Regulation, Spinning Reserves and Non-spinning reserves. The first two products are frequency regulation, while the remaining two are contingency reserves. Residual amounts of AS are procured in Real-Time as needed to cover outages and changes to the forecast. AS capacity is cleared on an hourly basis and Day-Ahead awards are notices at the same time as Day-Ahead energy. The CAISO requires a Real-Time energy bid to cover the range of Day-Ahead AS capacity awards and, in the absence of a submitted bid, inserts a default energy bid. To determine deliverability of AS capacity, the CAISO applies a number of compliance criteria and rescinds portions of awarded capacity that it determines to be undeliverable. For determining PDR compliance during contingency events when non-spinning reserves are dispatched, the CAISO employs a meter-before/meter-after baseline. The CAISO also requires telemetry for resources providing ancillary services.

Table 1 summarizes key information from the preceding sections on CAISO models and products:

TABLE 1
Direct Participation Resource Models

Parameter	PDR	RDRR	PL
Resource Minimum Size	0.1 MW	0.5 MW	1 MW
Resource Maximum Size	None*	50 MW for discrete dispatch option	NA
Day-Ahead Energy	Y	Y	Y
Real-Time Energy	Y	Y	Y
Non-Spinning Reserve	Y	N	Y
Metering	10-in-10 BL	10-in 10-BL, Approved Statistical	CAISO Meter
Telemetry	AS and 10 MW or Greater	N	Y
Demand Bidding/Scheduling	LSE	LSE	Custom LAP
Location Requirements	Sub LAP or Custom Model	Sub LAP or Custom Model	Custom Model

*Although there are no specific limits, resources 10 MW or larger must meet telemetry requirements

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3.1.4 Focus of Models for Program Integration Analysis

For the purpose of this analysis and report, only the PDR and RDRR models are being considered as possible integration opportunities. The implementation requirements for Participating Load extend beyond any practical implementation period. There is no workable Non-Generator Resource DR model in place today. As such, we have eliminated it for short-term consideration. PDR and RDRR models are, by their design, the two models most conducive to short-term program integration analysis. Participating Load and NGR DDR are not conducive for integration in the near term.

3.1.5 Market and Settlement Timelines

3.1.5.1 Wholesale Market Bidding

CAISO market bidding is a highly structured process with fixed inputs and firm timelines. The availability of program quantities must be known prior to bidding deadlines to seamlessly integrate into the wholesale market and minimize risk. Program design parameters need to be factored into the Master File through the Resource Data Template (RDT) and bid structure. Each resource has a distinct RDT that defines fixed parameters such as minimum and maximum event periods, maximum load reduction and number of daily events. Energy bids are submitted as price and quantity pairs for each hour and the price could be reflective of the translation of an event trigger such as heat rate.

3.1.5.2 Dispatch/Awards

CAISO award, dispatch and notifications come in various forms from multiple systems. Program notification timelines and technology capability determine wholesale product compatibility. Day-Ahead market results are communicated through the CAISO Market Results Interface (CMRI) application generally by 1 PM one day prior to the operating day, including weekends and holidays. Real-Time dispatches are communicated through Automated Dispatch System (ADS). ADS is designed as a "pull" notification while CMRI posts notifications that require some form of monitoring.

3.1.5.3 Wholesale Market Settlements

Each Demand Response resource is a distinct resource in the CAISO market. In addition to applying any existing validation and shadow processes to back office activity, performance validation requires interfacing with the CAISO Demand Response System for wholesale event performance results.

Meter data submission to the CAISO affects wholesale settlement timing. There are two deadlines for submitting verified meter data to the CAISO for settlement purposes. The first occurs 8 business days after the market trade date (T+8B); the second occurs at 48 business days after the trade date (T+48B). Submission of verified meter data by either of these deadlines initiates a process of rounds of statements resulting in settlements roughly a few weeks after each submission date.

3.1.6 CAISO Policy Developments

3.1.6.1 The Default Load Adjustment & the Net Benefits Test (NBT)

The purpose of the Default Load Adjustment (DLA) is to ensure that demand response providers and load-serving entities are not both compensated in the CAISO's market for a single reduction in demand, thereby ensuring the avoidance of a wholesale "double payment" for the demand response reduction. The CAISO filed for tariff authority with a provision that aimed to address double payment for PDR/RDRR load reductions by proposing to add back the amount of load reduction from the PDR or RDRR resource to the corresponding LSE's metered demand. By doing this, CAISO would not also pay the LSEs for the difference between their scheduled load in the Day-Ahead market and metered demand that was a result of the DR activity.

The mechanics of how the DLA is calculated hinge on the fact that the LSE schedules the underlying load for both the PDR and RDRR models. Therefore, the meter quantities reported by the LSE include any load reduction measured by a PDR or RDRR. As such, the CAISO can pay for both the instructed energy of the PDR and the uninstructed energy of the LSE at the same time. To offset the portion of measured load that contributed to the LSE uninstructed energy, the measured quantity of the PDR becomes the meter add-on to the LSE in the form of the Default Load Adjustment (DLA).

In a number of filings and orders FERC addressed the DLA and ultimately, in acceptance of the Order 745 compliance re—filing, maintained that the DLA could be applied only when the applicable LMP was below the NBT. That is, any DR is that is at or above the cost-effectiveness threshold is eligible for compensation at the full locational marginal price and should not include any DLA for the LSE. The price point at which DR is deemed to be cost effective to balance supply and demand as an alternative to generation resources is called the Net Benefits Test, or NBT. CAISO calculates the NBT for each month and posts this value by the 15th day of the preceding month.

In D.12-11-025, the CPUC ordered that any bundled customers bid into the CAISO market had to be bid at or above the applicable NBT in order eliminate some of the complexities of applying the DLA to DR resources. Much of the complexity stems from the fact that neither FERC nor the CPUC settled on a standard methodology for calculating the compensation from the DRP to the LSE when a DLA is applied. The CPUC largely avoids engaging the issue of payment by saying that if the DR is compensated at or above the NBT then the broader benefit of reduced cost to serve load is enjoyed by the LSE and no additional compensation is owed by the DRP.

The CAISO has appealed the FERC ruling regarding the applicability of the Default Load Adjustment. If the appeal overturns the current FERC ruling, the DLA could be applied to all awards and dispatches regardless of whether or not they are at or above the Net Benefits Test. If this were to be the case, the need for a financial settlement between the DRP and LSE would likely again surface.

3.1.6.2 Positive Uninstructed Energy and the Default Load Adjustment (DLA)

Despite the current rules that prevent bundled customers from being bid into the CAISO market below the Net Benefits Test (NBT), there are circumstances where event performance above the award/dispatch quantities could result in Real-Time energy settlement below the NBT and result in application of a DLA to the LSE. This could be problematic if it occurs with Direct Access program participants because it resurfaces the issue of the DRP compensating the LSE when they are not the same party[3].

In an example, with an applicable NBT of $50, the resource bids at $55 and receives an award. The resource then over delivers by 1 MW and the real-time price is $30. The resource is paid $30 for the over delivery, but since the real-time price is below the NBT, the CAISO adds 1 MW to the LSE metered demand for the same hour. Since the LSE is now obligated to pay imbalance charges for energy it did not consume, it may expect compensation from the DRP.

3.1.7 Demand Response System (DRS) Enhancements

The CAISO DRS requires entry of a broad range of information to create and maintain a registration. Each customer in an aggregation must be defined by its name, physical address, account number, load impact, DRP and Sub LAP. The collection of all locations in an aggregation is then selected for inclusion in a registration. Currently these processes are entirely manual and only accessible by a registered user through the DRS User Interface. The CAISO indicates that it will provide an API to facilitate these processes which should allow a DRP to leverage data that is already contained in internal systems for upload to the DRS without the resource intensive effort and risks associated with manual entry. The CAISO has yet to release any external business requirements that users can develop against. Without an operative API, it is impractical to include programs that have large volumes of participants or frequent changes in participants in a functional PDR or RDRR.

The CAISO DRS is the portal through which PDR and RDRR performance data is made available to the DRP for review. While the market results of a resource are provided in settlement statements, settlement data does not include data on the background calculations of the baseline and event meter data that would be used to validate the settlement statement. Currently the information is available but requires use of the DRS UI to access the performance data. A separate search is required to recall baseline data for one event. The performance API would allow more efficient access to event performance data information and allow integration with existing back office validation processes.

The CAISO has also committed to providing an API to download baseline and event performance information that better integrates into settlement validation business processes.

a. Known and Unknown Defects

Since the DRS has only been lightly used since deployment, there may be uncovered defects that need repair to ensure efficient management of PDR and RDRR resources. It is unknown at this time if any such defects

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[3] The DLA and the compensation issue could also arise with non-bundled customers outside of the imbalance energy scenario since the CPUC only requires that bundled customers are bid at the NBT or above.

would rise to a level to be considered critical to the point of impeding the registration or measurement of either a PDR or RDRR.

3.1.8 RDRR Deployment

The timing of the CAISOs Reliability Demand Response Resource (RDRR) Model deployment will impact the integration of programs utilizing this model. Specifically, the timing of the deployment will affect market integration of the Base Interruptible Program (BIP) insofar as it limits opportunities to test in Market Simulation. In its compliance filing of August 19, 2013 the CAISO requested an effective date of April 1, 2014 citing the need for adequate time to make modifications to the CAISO market systems, testing and market simulation. As of November 2013, the CAISO's release planning shows RDRR deployment in its Spring 2014 release which has pushed the market simulation to be very close to the implementation date. In doing so, if significant issues are uncovered during the market simulation, there might not be sufficient time for remediation prior to the planned release date.

3.2 California Public Utilities Commission (CPUC)

3.2.1 Electric Rule 24

Although Electric Rule 24 has loosely been in development for several years, the high-profile closure of the San Onofre Nuclear Generating Station (SONGS) and the planned retirement of other key generating units have brought a new sense of urgency to policy-makers calls for its completion. Fundamentally, it paves the way for direct participation, specifying the rules for Demand Response Providers (DRPs) who want to bid Bundled Customers into the wholesale market. Until finalization, bundled customers may not be bid into the ISOs markets by third party DRPs.

The proposed decision released by the CPUC on October 25, 2013 identified the main issues for consideration, covered in the following sections.

3.2.1.1 Competitive Neutrality

Language was introduced into the draft Rule 24 that attempted to establish greater competitive neutrality between third party DRPs and IOUs. The paragraph on competitive neutrality was subsequently refined, effectively limiting the ability of utility staff to share information that could be used for anti-competitive purposes. Although the enforcement mechanism is unclear, it is likely that there will be an extra set of protections for confidential DRP information. The broader implications of this development could indicate a larger divergence in responsibilities, roles and functions between staff doing work on retail and wholesale DR.

3.2.1.2 New Metering Responsibilities

There has been a broad consensus among stakeholders that Rule 24 will entail a new set of metering responsibilities for DR providers. CAISO Settlement requires aggregated and processed metered data – referred to as "Settlement Quality Meter Data" – which DR providers have not previously had to deliver. With these new responsibilities come a variety of process changes, requirements for the various parties and risk mitigation activities.

Acting as their own DRP and bidding their customers into the CAISO markets, PG&E must provide SQMD to the CAISO. This task poses another set of logistical concerns that could be non-trivial. At the very least, it would require adaptation and implementation of previous internal processes in order to coordinate meter data transmission with CAISOs data submission deadlines. Please see Section 3.1.5.3 for a discussion of the most germane CAISO settlement timelines and procedures.

3.2.1.3 Automatic Unenrollment for PDP Participants

In the recent PD related to Petitions for Modification (PFM) of D.12-11-025, the Commission approved an automatic unenrollment process for PDP participants, triggered by a DRP registering the customer at the

CAISO. Once unenrolled from PG&E's PDP rate option, the customer is disqualified for any outstanding bill protection. If the customer has any other DR obligations, the utility provides comments to the CAISO that the registration violates the guidelines for dual participation.

3.2.1.4 The Path towards a Final Rule 24

Two concurrent processes must be resolved in order to finalize Rule 24. The first is the final decision on the PFMs of D.12-11-025 submitted by the various stakeholders on August 23, 2013. The consideration of the Proposed Decision is currently scheduled for the Commission's December 5, 2013 Business Meeting. At that meeting, the Commission may adopt a Final Decision on the PFMs or may postpone adoption until a later date.

Secondly, on October 10, the IOUs jointly filed tier Three Advice Letters containing their draft Rule 24 tariffs (along with the relevant forms)[4]. Elements of the Rule and these forms were protested on October 30 by EnerNOC, Alliance for Retail Energy Markets and the Direct Access Customer Coalition but resolution is not expected to significantly delay the approval of Rule 24. In keeping with the Commission's desire to concurrently resolve all Rule 24 issues, the protests are expected to be decided in parallel with the PFM issues. Once a decision on the protests and the PFMs has been issued, each IOU will have 30 days to file specific tariffs, which comply with the Commission's decision. In addition, the IOUs will have 90 days after such approval to submit cost-recovery applications to implement Rule 24.

3.2.2 CPUC Order Instituting Rulemaking (OIR) R.13-09-011

The Order Instituting Rulemaking (OIR) for Demand Response Proceeding R.13-09-011 issued September 25, 2013 proposes potentially major long-term fundamental changes to utility-administered demand response. It has proposed changes to funding cycles, the creation of a resource adequacy capacity payment mechanism, and the re-classification of existing programs.

3.2.2.1 Extension of DR Funding Cycle

The OIR proposes extending the tri-annual funding cycle with the objective of promoting longer-term consistency and heightening the overall impact of DR programs. A decision on the new funding cycle will not come in time to meet the January 31, 2014 filing deadline for the next program cycle. As a result, the current discussion has centered on bridge funding for 2015 and, potentially, 2016.

The Commission has issued a proposed decision that addresses bridge funding. The proposed decision allows an opportunity in the first quarter of 2014 for parties to file proposed program modifications. PG&E may be required to use this opportunity to make all program related changes for PDR / RDRR. This opportunity, together with the future longer-term measures to be prescribed by the OIR, could introduce additional complexity to the transition of PG&E's demand response programs by creating two simultaneous trajectories of changes that need to be accounted for and possibly implemented.

3.2.2.2 Bifurcation of DR Programs

The OIR envisions an effort to divide demand response programs into two separate groupings. Demand-side or Load-modifying demand response are programs and rates that are customer-focused such as Peak-Day Pricing or Smart Rate. Supply-side DR has the ability to be bid into the CAISO markets due to greater resource flexibility and control. A major work of the proceeding is to better define these categories and the criteria by which they will classify current and future programs.

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[4] IOUs are directed to file the advice letter within 90 days of the final staff-led Rule 24 workshop which took place October 11, 2013.

3.2.2.3 New Developments in Resource Adequacy

The Energy Division in coordination with CAISO has proposed a "Joint Reliability Framework" to develop a resource adequacy capacity payment mechanism for DR. Although these mechanisms are still in the nascent phase of development, a goal of these endeavors is to create more long-term revenue certainty for demand-side resources.

3.3 Federal Energy Regulatory Commission (FERC)

The RDRR Compliance Filing is now in FERC's hands and must be approved in order for implementation at CAISO by the requested April 1, 2014 start date. While there is no reason to believe that there are any significant issues with the CAISO's refiled tariff modifications for RDRR, an unforeseen delay could significantly stall the integration of some programs.

3.4 Modifications to Aggregator Managed Portfolios

PG&E is considering several changes to AMP that could affect wholesale market integration. Changes that directly affect market compatibility are discussed here, while other changes that that could affect the use of the AMP contracts are considered in the action plan.

AMP contracts are categorized into eight Local Capacity Areas (LCA) in PG&E service territory. Currently, nomination and settlement for these contracts are done on a LCA by LCA basis. PG&E plans to file changes that will propose moving to designation, dispatch, (but not program capacity settlement) to the Sub-LAP level. The shift to a Sub-LAP dispatch would be a step closer to compatibility with CAISO wholesale market models that require resources to be located within a single Sub-LAP.

Another proposed modification would generate more variability in the amount of load shed that contracted AMP resources could provide. Currently, aggregators may revise their commitment levels by (+/-) 15% from the system-wide commitment level by February 1 of each season. That revised amount stays into effect for the duration of the season. However, proposed changes would reduce the potential seasonal percentage change from 15% to 10%, and add an additional 5% monthly revision. If these changes are not managed appropriately, they could introduce added intricacy to wholesale market operations. If contracted figures are fluctuating due to moving customers in and out of programs, they could produce an additional variable to monitor in ensuring that PDR/RDRR resources uphold the minimum size requirements.

4 Program Analysis

In the analysis of the various programs, the effort focuses on finding intersections between program parameters and CAISO market models and products. These intersections are not necessarily aligned since DR programs and CAISO markets exist for different purposes. In particular, CAISO markets and products are designed for constant use and selected by economic merit order, while DR programs are typically designed for infrequent use to mitigate specific grid conditions and selected by triggers related to the specific condition. Even when the DR program trigger includes a price threshold, there is not necessarily a correlation with the corresponding CAISO Day-Ahead or Real-Time energy market-clearing price.

4.1 Methodology

For the analysis, we rely on two progressive screens of Program Criteria cross-referenced against CAISO model and product requirements to determine a best fit and as well as an initial path to Direct Participation in the summer of 2014. The first assessment scores and evaluates all programs; the second assessment scores for those programs found to be most compatible from the first assessment.

Scoring uses a 0 to 5 ranking from lowest to highest. A score of zero indicates that there is a conflict eliminating a particular program from current consideration but does not presume that the conflict will persist in the long term. A score of 5 indicates a best fit for that particular criteria and allowing integration of that component without modification. Scores between 1 and 4 indicate that the criteria is not a perfect fit and may require modification of a particular practice, or at the lower end, may require a major change such as a tariff modification.

The following summary table provides some of the basic statistics that have informed our analyses. Our sources of data for this report have been various DR Program materials supplied by PG&E, PG&Es September 2013 ILP Report, as well as a general reading of PG&E program tariffs.

TABLE 2
PG&E Demand Response Programs: Basic Statistics*

Program	Service Accounts	Ex Post Estimated MW	Zonal Dispatch
BIP	279	245	Sub-LAP
OBMC	25	0	Reliability Zone
SLRP	0	0	System
SmartAC™ – Commercial	5,777	2	System
SmartAC™ - Residential	151,435	86	System
AMP – DA	571	122	System/LCA
AMP – DO	1,824	208	System/LCA
CBP – DA	24	3	Sub-LAP
CBP – DO	464	29	Sub-LAP
DBP	955	36	Sub-LAP
PDP	6,088	31	System
SmartRate – Residential	119,593	33	System

**Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for September 2013*

4.2 Market Compatibility Assessment of All Programs

4.2.1 Evaluation Criteria

In the initial screen, all programs were analyzed to determine their compatibility to be represented as a CAISO market resource. This evaluation considers the primary elements of creating a PDR or RDRR: A) meeting critical registration requirements; and, B) maintaining those registrations.

4.2.1.1 Criteria for Evaluating Ability to Meet Registration Requirements

The criteria that we consider in columns 3-5 of the table below stem from the CAISO PDR/RDRR Resource Requirements. Please consult Section 3.1.2 above for additional information on these market models. The following clarifies how these criteria were applied to each program:

i. *Can the participants in the registration be contained in a single sub-LAP?*
PDR/RDRR requirements specify that each location in the registration be in the same sub-LAP. Programs that can only be dispatched on a system-wide basis pose integration challenges because it is neither practical nor prudent to dispatch a full program when only a subset of that program is dispatched in the market. For zonal programs, not having a Sub-LAP dispatch introduces other complexities stemming from the fact that CAISO resources dispatch and settle as a unit. For instance, if one Sub-LAP straddles two LCAs, then both LCAs must be called for any market awards. However, if one of these LCAs performs and the other does not, settlements are not disaggregated to reflect the uneven performance. A program that can call events by Sub-LAP makes a better market fit because one may dispatch PDRs and program Sub-LAPs on a 1:1 basis. Programs that can be dispatched at the Sub-LAP and that are settled at the Sub-LAP are even a better fit. Therefore, a program like this would earn a high score in the table below. Note that many programs either fit, or do not fit the ability for Sub-LAP dispatch, without much gray area in between. For this reason, a majority of the programs have been scored as either a 0 or a 5.

ii. *Can all customers in the registration be represented by a single LSE?*
Each location in a PDR/RDRR must be served by the same LSE. Therefore, a program with mixed bundled/non-bundled customers yields some measure of additional complexity. This is due to the fact that there must be enough customers served by a single LSE within the same Sub-LAP to meet certain PDR and RDRR requirements. A program with only bundled customers would earn a higher score because the probability of finding enough customers within each Sub-LAP would be higher than a program with a mix of non-bundled customers.

iii. *Can the customer aggregation meet the resource minimum size requirements?*
Each PDR/RDRR must be able to provide load reductions of at least 100 and 500 kW, respectively. Smaller customer load sheds would require a larger number of customers per registration and therefore more monitoring and logistical burden. The ideal program would have customers with load shed potential at or above the requirements. Note that we have relied upon the Average Ex Post Load Impact kW / Customer from the September 2013 ILP Report[5] to estimate the average load shed potential of a typical program customer.

4.2.1.2 Criteria for Evaluating Ability to Manage Resource Registration

In columns 6-8, the amount of registration management necessary for each program given the existing manual processes of the CAISO DRS is scored. We include the following specific measures:

i. *The consistency and durability of program participants:*
How often will the registration need to be updated to add, remove locations? If there is frequent movement in and out of programs, this will require frequent registration additions and subtractions, resulting in much management and a lower score. From a registration management perspective, a high-scoring program will have a stable customer group with little to no changes in composition.

ii. *The potential for a customer to be assigned to more than one active registration and multiple program participation issues:*
Currently customers cannot be in more than one active CAISO registration at any given time. How much monitoring is necessary to ensure that the same customer is not included in multiple registrations? A customer group that is not enrolled in more than one program and does not frequently shuffle between different programs, all else equal, would earn a higher score because there is a lower probability of them being concurrently enrolled in two or more registrations. Further, there

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[5] Pacific Gas and Electric Company Monthly Report On Interruptible Load and Demand Response Programs for September 2013: http://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/cs/September2013_ILPreport.pdf

are cases where a rate such as PDP or Smart Rate might create the situation where a customer is not available for dispatch in its assigned market resource if the rate is triggered before or even after the market resource is awarded or dispatched. While the flexibility for MPP is a benefit, it must be managed appropriately when considering it for integration. A program with frequent MPP would earn a lower score since it entails additional layers of monitoring and management to ensure that registration are continually updated to track customer movement.

iii. *The volume of customers in a program:*

Is the entry of the data necessary to create the registration feasible given the lack of a DRS API? If the number of customers needed to create a registration is too high, then creating a resource can become a very time-consuming effort. The smaller the customer group that is needed to create the registration, the more manageable data entry becomes. A program with fewer service accounts, all else equal, would earn a higher score.

TABLE 3
Market Compatibility Assessment of All Programs

PROGRAM:		CAISO PDR/RDRR Resource Requirements			Resource Registration Management			Total Score
		Contained in Single SLAP	*Single LSE*	*Minimum Resource Load Shed (PDR/RDRR 100/500 kW)*	*Registration Consistency*	*Only active one Registration*	*Manageable Data Entry (w/o API)*	
BIP	*Compatibility*	Dispatchable by SLAP	187 Bundled / 64 Non-Bundled	877 kW	Seasonal Opt Out with exceptions	Multiple Program Participation	279 Participants	
	Score	5	3	5	5	2	5	25
CBP	*Compatibility*	Dispatchable by SLAP	546 Bundled / 435 Non-Bundled	121.50 kW (DA) 62.80 kW (DO)	Frequent movement between programs	Frequent MPP	464 (DO), 24 (DA) Participants	
	Score	5	3	4	3	2	4	21
DBP	*Compatibility*	Dispatchable by SLAP	685 Bundled / 255 Non-Bundled	37.88 kW	Frequent movement between programs	Frequent MPP	955 Participants	
	Score	5	3	3	3	2	3	20
AMP	*Compatibility*	May be dispatchable by SLAP in near future	2,012 Bundled / 533 Non-Bundled	214.4 kW (DA) 114.2 kW (DO)	Frequent movement between programs	Frequent MPP	1,824 (DO), 571 (DA) Participants	
	Score	4	3	5	3	2	2	19
SmartAC™ - Com	*Compatibility*	Dispatchable by SLAP	Bundled / Non-Bundled (5,777 Total)	0.29 kW	Fairly stable customer group	Some MPP	5,777 Participants	
	Score	5	5	2	4	3	1	20
SmartAC™ Res	*Compatibility*	Dispatchable by SLAP	Bundled Only	0.57 kW	Frequent changes in composition	Interactions w/ SmartRate	151,435 Participants	
	Score	5	5	3	1	1	0	15

PROGRAM		CAISO PDR/RDRR Resource Requirements			Resource Registration Management			Total Score
		Contained in Single SLAP	*Single LSE*	*Minimum Resource Load Shed (PDR/RDRR 100/500 kW)*	*Registration Consistency*	*Only active one Registration*	*Manageable Data Entry (w/o API)*	
PDP	*Compatibility*	Not Dispatchable by SLAP	Bundled Only	18.55 kW (X>200 kW) 0.36 kW (X<200 kW)	Frequent changes in composition	Frequent MPP	6,088 Participants	
	Score	0	5	3	3	2	0	13
Smart Rate	*Compatibility*	Not Dispatchable by SLAP	Bundled Only	0.28 kW	Frequent changes in composition	MPP w/ Smart AC™	119,593 Participants	
	Score	0	5	1	1	1	0	8
OBMC	*Compatibility*	Dispatch by Reliability Area	18 Bundled / 7 Non-Bundled	N/A	No changes in composition	Some MPP	25 Participants	
	Score	1	3	0	5	3	5	17
SLRP	*Compatibility*	Not Dispatchable by SLAP	Bundled Only	N/A	No Enrollees	Some MPP	0 Participants	
	Score	0	5	0	0	3	0	8

4.2.2 Assessment

In this initial screen there are five programs that would require protracted effort to integrate into the wholesale market: in their current design, Peak-Day Pricing, SmartRate, SmartAC™-Residential, OBMC, and SLRP have the least potential for wholesale market integration in the near-term due to the need for significant program modifications or adaptation to CAISO requirements.

Peak-Day Pricing and Smart Rate do not lend themselves to inclusion since they are operated on a system-wide basis. System-wide dispatch introduces a critical hurdle into wholesale integration. Consider the situation where the entire PDP or Smart Rate customer-base is used to create PDR resources with one resource per Sub-LAP. Now, lacking a more granular dispatch, any resource that cleared the market would require that the entire program be called. This dynamic could potentially disrupt the pricing of the Real-Time market due to unaccounted dispatch. PDP & Smart Rate would need to be modified to support Sub-LAP dispatch in order to be represented in the market.

Given its extremely large number of customers, SmartAC™ Residential is likely too unwieldy to manage in the DRS even if the registration API is available.

There are problems with the integration of OBMC and SLRP that have led us to leave them outof the next stage of our analysis. For OBMC, dispatch by reliability area or system is predicated on the need for rotating outages. Absent such a circumstance, there would be no basis on which a market award could translate into an event or dispatch signal to the customer. The first obstacle with SLRP is simply that it has no current enrollees from which registrations may be created.

4.3 Assessment of Higher Feasibility Programs

With the determination made regarding the ability of each program to be managed as a resource, market participation compatibility is applied to the subset of programs from the initial screen. Further, in this step of analysis CBP and AMP are broken out into their defined sub categories of Day-Ahead and Day-Of since there are differences between these notification timeframes that impact compatibility.

4.3.1 Evaluation Criteria

The following table builds upon the analysis criteria of the preceding sections. The table balances program criteria against CAISO model and product requirements to determine a best fit.

For these higher-compatibility programs, we have selected four distinct criteria to quantify CAISO market integration capability.

i. *Market Product Fit:*
How well does the program interface with the requirements for CAISO market products? For PDR the practical application is Day-Ahead Energy (DAE) since it generally fits well with program timing. Real-Time Energy and Non-Spin have short dispatch notice times and short event periods that do not mesh well with traditional program design. In addition, Non-Spin requires telemetry. Specific to programs that would utilize RDRR, the quasi Ancillary Service (AS) of Reliability Energy does not require telemetry which creates favorable scoring.

ii. *Use-Limits:*
Operational constraints such as notification timing, minimum / maximum event length and calls per day are managed through the Resource Data Template (RDT), a spreadsheet through which resources provide the CAISO with operational characteristics. Ultimately, these parameters impact how and when a resource is selected in the CAISO market optimization. For example, minimum and maximum run-times determine if a contiguous number of hours are selected. Specific program constraints need to be considered to determine if they can be managed as they currently exist or if they can be adjusted through program modification. This particular metric considers how well these program constraints can be captured using the parameters available in the RDT.

iii. *Bids:*
Bid Price considers how easily a program trigger can be represented by one or more price quantity pairs. Market bid structure is one area of flexibility that may help bridge the gap between DR Program triggers and market integration. For some programs with one or more fairly uniform event triggers, the translation may be fairly straightforward. For example, if a program is called whenever a specific zonal or market heat rate is reached, a corresponding bid price based on average market prices at the time could be calculated. However, for a program with triggers (such as PG&Es threshold temperature) that do not translate well to the wholesale market, determining a meaningful market bid price and quantity could be more challenging.

iv. Dispatch:
Determines how program notification timing fits with the CAISOs market result timeline A program that has an event notification time that is after the CAISO market award or dispatch scores high while any program that requires event notification before the award or dispatch scores low. In particular, the Real-Time energy market dispatch notice that comes merely 2.5 minutes prior to the 5-minute

dispatch interval is not compatible with traditional program operating criteria with the possible exception of direct control capabilities.

4.3.2 Assessment

TABLE 4
Assessment of Higher Feasibility Programs

		Product	Use-Limits	Bid	Dispatch	Total Score
BIP	*Compatibility*	Day-Ahead and Real-Time Reliability Energy	4 Hour Maximum	Prescribed by RDRR Design	30 Minute Notice	
	Score	5	4	5	5	19
CBP Day-Ahead	*Compatibility*	Day-Ahead Energy	1 to 4 Hour Minimum, 2 to 8 Hour Maximum	15,000 BTU Heat Rate	3 PM Day Prior	
	Score	5	4	5	5	19
CBP Day-Of	*Compatibility*	Day-Ahead Energy	1 to 4 Hour Minimum, 2 to 8 Hour Maximum	15,000 BTU Heat Rate	3 Hours Prior	
	Score	4	4	5	5	18
SmartAC™ Com	*Compatibility*	Real-Time Reliability Energy	6 Hours Maximum	Emergency or $1,000	15 to 30 minutes prior	
	Score	5	2	2	5	[redacted]
AMP Day-Ahead	*Compatibility*	Day-Ahead Energy	4 Hour Minimum, 6Hour Maximum	15,000 Heat Rate	3 PM Day Prior	
	Score	5	3	5	5	18
AMP Day-Of	*Compatibility*	Day-Ahead Energy	4 Hour Minimum, 6Hour Maximum	15,000 Heat Rate	30 Minutes Prior	
	Score	4	3	5	4	16
DBP	*Compatibility*	Real-Time Energy	2 Hours Minimum	CAISO Load 43,000 or Temperature	12 PM/4 PM One Day Prior	
	Score	1	3	1	2	[redacted]

From the market compatibility analysis, SmartAC™ and DBP in their current configuration have a low compatibility for market participation. While SmartAC™ has the desirable characteristic of being quickly dispatchable without customer intervention which would be suitable for Real-Time energy or even Non-Spinning reserve, it lacks a trigger that can be easily translated to an energy bid other than the tariff price trigger when Day-Ahead energy price is $1000. There is no guarantee, however, that the same price would be reached in the Real-time market. Further, Non-Spinning reserve requires telemetry which would be onerous to provide for all program participants.

Demand Bidding Program is incompatible with Day-Ahead energy due to timing issues. The deadline to post bids for DBP is 4 PM the day before. However, this occurs after the Day-Ahead market bidding deadline of 10 AM, effectively rendering DBP incompatible.

By name, programs with Day-Of products would seem to logically go to the CAISO Real-Time market but the five-minute dispatch granularity prevents this. Somewhat counterintuitively, Day-Of products can be a better fit for the CAISO Day-Ahead market. If a program with a Day-Of product is bid into the Day-Ahead market, Day-Ahead awards are provided by 1pm, the day before the trade date. The actual event notification of those awards does not have to occur the same day and depending on circumstance can wait until the Day-Of event deadline.

Primarily because the RDRR product was specifically designed to accommodate BIP, the program scores very high. Both CBP and AMP score similarly with only a slight differentiation in use-limit scores. The primary use-limit issue is that a minimum dispatch period of greater than one hour decreases the likelihood that consecutive hours will clear the market for all hours

As such, the CBP 1-4 hour option is a better fit than CBP options with longer minimum run-times, or the four-hour AMP event minimum. The minimum run-time use-limit could, however, be managed by submitting an RDT with a shorter minimum run-time than the program definition, but that could create a disconnect between the number of hours that clear the market and the number of hours of a program event.

4.4 Conclusions

Each of the three higher compatibility programs have different paths to inclusion in the CAISO market. None is a perfect fit and each requires different approaches, effort and timing due to both the specifics of the program and challenges, some of which are not entirely within PG&E's control. Equal treatment of all program participants plays a major factor in these paths to market inclusion and this, with other factors, would prevent the bidding of all participants for all available program hours until several outstanding issues can be fully resolved.

4.4.1 Program-wide Considerations

The following are considerations that affect all programs in terms of market compatibility.

4.4.1.1 Non-Bundled Customers: Dealing with LSEs

Issues related to the treatment of non-bundled customers affect implementation across all programs. First, programs are called based on product and zone rather than customer type. Generally, there is either an equal distribution of bundled and non-bundled accounts and MW or there is a significant MW impact from non-bundled customers. Until the issues associated with non-bundled program participants are resolved, discrepancies in the quantities bid and awarded/dispatched in the market and the amount of MW called by event will occur.

In order to bid a direct access customer into the CAISO markets, the DRP must enter into a formal agreement with the LSE of that customer. However, there is no statutory obligation which compels an LSE to enter into such an agreement (i.e. the reciprocal of Rule 24). In fact, many LSEs may resist an attempt on the part of the

DRP to enroll their customer in a registration, especially if the LSE may wish to become a DRP at some point in the future and do just the same. The development of a pro-forma agreement between the utility DRP and non-bundled LSE would provide a platform to engage in negotiations. Such an agreement could document the relationship between the two parties and memorialize the fact that the DRS requires LSE registration of their customers.

In addition to the development of an agreement, an outreach plan to the non-bundled LSE is necessary. The aggregator that enrolls a participant in a program is not likely to be the LSE and might not have the appropriate contact for the LSE. It then falls on the UDC to provide the appropriate LSE contact.

Once a DRP and LSE agreement is in place, the LSE also needs to be enrolled in the CAISO DRS to perform the registration review, validation and access performance data. The CAISO has no formal process by which it engages LSEs for inclusion in the DRS and it may require an outreach effort by the appropriate CAISO personnel to engage with candidate LSEs. In the alternative, the DRP and LSE agreement would need to outline the method by which the LSE will be presented to the CAISO either through stipulated authorization by the DRP in the agreement or as a term of the completion of the agreement.

Although in the short-term, the LSE engagement issue can be circumvented by starting to bid in bundled customers, eventually the process by which DRPs and LSEs contract an agreement so that the LSEs customer may be bid into the wholesale market must be formalized.

4.4.1.2 Monthly Nomination Deadlines

Monthly nomination deadlines that are only five business days prior to the beginning of the month do not mesh with the DRS registration process. When a registration is updated through either the addition or subtraction of accounts, the LSE and UDC have up to 10 business days to complete their review and the CAISO approval process allows for an additional 10 business days to approve the registration. As such, a more workable lead-time for nomination changes would be 20 business days prior to the beginning of a month. A change of this magnitude could have a negative impact on program aggregators and participants and would require changes to program tariffs and contracts.

While the process can be managed within a shorter timeframe when the utility performs all three roles (DRP, LSE and UDC) in close coordination with the CAISO, it is not reasonable to expect that this would be the case when non-bundled LSEs are involved or when issues arise in the review and approval process. In the absence of this issue being addressed through longer nomination lead times, a mitigating strategy is to withhold changing resources from bidding until the registration and meter data processes are complete.

4.4.1.3 Internal PG&E Process Changes

Integration of existing programs will require changes and adaptation to various internal processes. The extent of these changes will not be known until implementation plans are fleshed out in subsequent phases of the project. In the interim, some changes may be addressed through manual intervention but in the long run or upon determination of the extent of the impact, systematic changes will be necessary. For example, each time a registration is updated and approved, 45 days of historical meter data for the updated registration aggregation is required to be submitted to the CAISO. This would create an additional burden on internal processes. To best identify these impacts and possible solutions, program integrations should not be considered in isolation.

4.4.2 Program-specific Conclusions

4.4.2.1 BIP

From the analysis, BIP is nearly a natural fit for inclusion in RDRR primarily because the RDRR model was designed to accommodate BIP. The program scored high as would be expected. There are a number of transitional issues to be addressed in the implementation plan such as the viability of manual data entry of registration data in the CAISO DRS through the user interface and the need to wait for the availability of the registration API.

Due to the circumstance of program use or dispatch, issues surrounding bundled and non-bundled participants would be less of a concern than it might be for a program that has a larger impact from non-bundled customers. The following table shows the breakdown of participants by Sub-LAP. Note that the approximate resource size by bundled and non-bundled accounts below have been extrapolated, reflecting the maximum resource registration MW and not necessarily the dispatchable quantity.

TABLE 5
Potential BIP Resources by Sub-LAP

SLAP	**Bundled**		**Non-Bundled**	
	Service Accounts	**Appx Resource Size MW**	**Service Accounts**	**Appx Resource Size MW**
Central Coast PGCC	*****	*****	*****	*****
East Bay (Bay Area) PGEB	*****	*****	*****	*****
Geysers PGFG	*****	*****	*****	*****
Fresno PGF1	*****	*****	*****	*****
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	*****	*****	*****	*****
Total	**186**	**240.68**	**64**	**185.73**

4.4.2.2 CBP

There are a number of operational impacts that need to be considered when integrating CBP into the wholesale market that ultimately need to be factored into an implementation plan. These impacts are a consequence of the fact that CBP, in its original design, was intended to be managed, scheduled and dispatched by the utility. The first impact is the disconnect between the CAISO market clearing price and the CBP triggers. The second impact is the issue of timing as to when it is actually available for market bidding. The third is that any CAISO market award (full or partial) for a CBP based resource will require the dispatch of all CBP aggregators in the same zone and with CBP options and products as the CBP based resource.

In the first case, the primary trigger to call a retail CBP event is a PG&E incremental system heat rate of 15,000 BTU/kWh. Multiplying this heat rate by a daily or hourly PG&E gas price ($/BTU) converts it to an equivalent energy price ($/kWh). It is important to note that the values used to calculate this equivalent energy price are PG&E's values for providing service to PG&E's bundled customers. The actual market clearing price determined by the CAISO is based on many different factors none of which directly relate to the factors used by PG&E. The end result is that the trigger for PG&E's retail CBP may be met while the equivalent energy price is not reached in the CAISO's markets. The converse is true as well.

In the second case, PG&E typically determines if it will call the retail CBP event prior to the deadline for submitting bids to the CAISO. The decision is typically based on a PG&E system heat rate of 15,000 BTU/kWh or greater. When PG&E determines the need to call a CBP event prior to markets closing, any bids submitted to the CAISO for the CBP based resource in the same timeframe will need to be withdrawn. If, however, the decision to dispatch the retail CBP occurs after the deadline for submitting CAISO bids, then PG&E will have to track the resource in the CAISO market and submit a SLIC should the resource receive a market award. In the case where it is determined that a retail program event is not needed, the currently submitted CBP based bids can continue as submitted.

For the third case, CBP requires equal treatment for all aggregators and customer types (bundled and non-bundled) with the same options and products within the same Sub LAP. As a consequence, all aggregators with the same options and products within the same Sub LAP as the CBP resource must be curtailed when a CBP based resource is dispatched -- even when these other aggregators were included in a different CBP resource or even no resource at all. It is important to note that all similarly situated aggregators be notified of an event even if the market result was for a portion of the bid in quantity. In both the second and third case, more MW are called at the event level than what was cleared and dispatched by the market. Also for both cases, the prospect of DR fatigue and exhausting of available event hours is possible and would need to be factored into any bidding strategy.

In the third case not all resources and participants in the same Sub LAP are guaranteed equal treatment by the CAISO market. If initially, only bundled customers are registered and included in resources and bid into the market and dispatched, all participants in the same Sub LAP would need to be called as an event. Even if non-bundled customers are bid in a distinct resource in the same Sub LAP, there is no guarantee that, even with the same bid price, that both resources would be called. In either case, if one resource were to clear the market, all associated participants within the same Sub LAP would need to be informed of an event.

A partial implementation of Day-Ahead Product of select Sub-LAPs provides the shortest route to integration due to the manageability of all issues which will presume to be dealt through manual processes. This requires that the number of resources be kept to a minimum while at the same time providing a presence of several MW in the CAISO market.

TABLE 6 **CBP Day-Ahead 1-4 Hour Resources by Sub-LAP**				
SLAP	**CBP Day-Ahead Bundled**		**CBP Day-Ahead Non-Bundled**	
	Service Accounts	**Appx Resource Size MW**	**Service Accounts**	**Appx Resource Size MW**
Central Coast PGCC	*****	*****	*****	*****
East Bay PGEB	*****	*****	*****	*****
Fresno PGF1	*****	*****	*****	*****
Los Padres PGLP	*****	*****	*****	*****
South Bay PGSB	*****	*****	*****	*****
San Francisco PGSF	*****	*****	*****	*****
Stockton PGST	*****	*****	*****	*****
Total	**10**	**5.532**	**3**	**1.41**

Note: This table relies on reported CBP nomination values from October 2013 to approximate resource size

The determination of Sub-LAPs most suited for initial integration starts by analyzing bundled customer and non-bundled customer make up. The Day-Ahead product includes a small reasonably stable set of enrollees/nominees as a sub-set of the Sub-LAPs. The inclusion of the four bundled-only Sub-LAPs (Fresno, Los Padres, South Bay and Stockton) could provide PG&E with four PDRs, totaling roughly 5.34 MW.

In the near future PG&E plans to file an Advice Letter for CBP that will modify the capacity payment process and no longer require that bundled and non-bundled customers be submitted as separate nominations[6]. When a CBP event is called for one or more Sub-LAPs, the Hourly Delivered Capacity Ratio for the event hour will be calculated on a cumulative basis for Aggregator's performance in all Sub-LAPs that received a Notice of the CBP event for the hour. This modification makes the CBP program less compatible with the wholesale markets because the aggregator is able to meet its CBP load reduction commitments though a combination of called Sub-LAPs. In comparison, the wholesale market requires that load reduction commitments be contained in the Sub-LAP.

4.4.2.3 AMP

A threshold issue for AMP is to process the proposed changes to the Contract/Tariff that allows dispatch by Sub-LAP for Product A (Day-Of) and Product B (Day-Ahead). In a manner similar to CBP, the planned change to AMP will also include the changes that make the capacity performance measurement and payment based on the a combination of called Sub-LAPs. While the move from LCA to Sub-LAPs make AMP more market compatible, making the capacity performance and payment on a combination of Sub-LAPs makes AMP less compatible with the wholesale markets. The change to performance and payment introduces the potential that an aggregator would be less focused on event performance in each Sub-LAP and cause wholesale settlement imbalance charges.

Even after these changes are processed, due to significant MW contribution of non-bundled customers, LSE agreement issues should be resolved in advance of integration. The number of participants and frequency of

[6] The current AMP contracts do not require that bundled and non-bundled customers be in separate nominations.

changes to nomination also beg the deployment of a functional DRS registration API. Both the impact of the number of participants and the contribution of non-bundled customers are shown in the following table. It is important to note that the non-bundled customer quantities also need to be further subdivided by individual LSE when creating PDRs. This will result in smaller resource size(s), additional registration administration and ultimately operational challenges.

TABLE 7
Potential AMP Resources by LCA using September Nominations as Proxy

	Product A Day-Of LCA				**Product B Day-Ahead LCA**			
	Bundled		**Non-Bundled**		**Bundled**		**Non-Bundled**	
Local Capacity Area[7]	**Service Account s**	**MW**	**Service Account s**	**MW**	**Service Account s**	**MW**	**Service Account s**	**MW**
Greater Bay Area	*****	*****	*****	*****	*****	*****	*****	*****
Greater Fresno	*****	*****	*****	*****	*****	*****	*****	*****
Humboldt	*****	*****	*****	*****	*****	*****	*****	*****
Kern	*****	*****	*****	*****	*****	*****	*****	*****
Northern Coast	*****	*****	*****	*****	*****	*****	*****	*****
Other	*****	*****	*****	*****	*****	*****	*****	*****
Sierra	*****	*****	*****	*****	*****	*****	*****	*****
Stockton	*****	*****	*****	*****	*****	*****	*****	*****
Total	616	93.68	166	17.195	364	46.94	132	25.31

Note: This table relies on September AMP Nomination data as a proxy for potential MW resource size

5 Roadmap (High-Level Action Plan)

5.1 Recommendations

Olivine recommends that PG&E integrate their Demand Response into the wholesale market by taking a focused and considered approach. By targeting subsets of high-priority programs there would be little or no impact to customers currently enrolled, allowing for the refinement of internal procedures and cycles of learning to support the continuation and expansion of the process.

Olivine recommends developing a thorough review and implementation plan to address the specific procedures and issues involved that prioritizes the following programs for integration into CAISO wholesale markets

- BIP (RDRR) – As Reliability Energy

[7] This analysis will have to be performed on a Sub-LAP basis.

- CBP Day-Ahead Bundled Customers for the 1-4 hour product in Sub-Laps (PDR) only containing bundled customers. - As Day-Ahead Energy
- AMP Day-Of Bundled Customers in select Sub-Laps (PDR) – As Day-Ahead Energy[8]

In these cases and based on a preliminary review there should not be any tariff or contract changes required beyond those currently in process for initial partial integration into the wholesale market. The prioritization approach also supports PG&E's ability to integrate some of their programs into the wholesale market within 2014 by providing options that would either not rely upon agreement by outside parties such as other LSEs, the CAISO to implement RDRR, or an API registration. Since each of these items create significant and different risk to the timing of integration of any one program, we believe it is prudent to address the integration of these three programs in parallel.

5.2 High-Level Action Plan

Below is a high-level action plan identifying the items to be addressed. This is not meant to be a detailed implementation plan but to provide a summary roadmap of the items to be addressed to provide for integration of the identified programs.

TABLE 8

High-level Action Plan
Wholesale Market Integration of PG&E DR Programs

Item	*Program*	*Timing (2014)*	*Comments*
Develop detailed implementation plan	Various	ASAP	A detailed implementation plan should be developed as soon as possible to support integration in 2014 and to allow time to for contingency plan development.
Input to R.13-09-011 proceeding.	All	Ongoing	Lessons learned from analysis and integration efforts should provide pertinent insights into market compatibility, design and other alignment issues for both Phase 1 (bridge funding and pilot proposals) and Phase 2 (foundational issues such as need for bifurcation).
Separation of Bundled and Non-Bundled Customers	All	1Q	Validate the separation to easily create and bid Bundled and Non-Bundled customers separately.
Evaluate customers by product and Sub-LAP	AMP	2Q	As a back-up plan, determine possible subset of customers that could be registered manually if API is not available for initial integration
Changes in Operating Procedures	CBP	1Q	Customers are currently provided indications prior to notification required by tariff requirements. Discontinuing early indication would eliminate any potential confusion with wholesale market award

[8] Assumes one of the following: 1) PG&E is willing to call and that the aggregators allow PG&E to call all bundled and non-bundled customers, and that PG&E enters into an agreement with the non-bundled customer's LSE. 2) PG&E requires the AMP aggregator to exclude non-bundled customers from its nomination for that sublap.

TABLE 8

High-level Action Plan
Wholesale Market Integration of PG&E DR Programs

Item	*Program*	*Timing (2014)*	*Comments*
			timing.
Separation of Bundled and Non-Bundled Customers	BIP	1Q	Evaluate market impacts if only Bundled Customers are able to be bid initially but all customers are called. Expected impact is low and not an issue in an emergency situation. Need to validate.
Sub-Laps	AMP	2Q	Determine if nominations to Sub-LAPs meet resource size requirements.
Procurement Impacts	All	1-2Q	Evaluate impacts to procurement procedures
RDRR Implementation	BIP	2Q	Timing of CASIO market simulation and CAISO final deployment may change. Alternative plans to be developed to address possible issues including PG&E's ability to complete testing and endorse RDRR.
DRS Registration API	BIP	2Q	Without CAISO's planned release of the API for registration, manual registrations would be required and may limit registration volume.
DRS Registration API	AMP	2Q	Registration API assumed to be required to manage volume of changes
DRS Performance and Baseline API	All	2Q	Without the Performance and Baseline API there may be a limit to how many resources can be processed by back office. Determine if in the absence of the P&B API if a third party service can access and provide needed information from DRS
Contract/Tariff Changes	AMP	2Q	It is assumed that the contemplated nomination to Sub-LAP changes are approved and effective by the summer of 2014. Contingency plans need to be developed if there is not approval or a delay in approval and aggregation remains at LCA.
Changes in Operating Procedures	AMP	2Q	Due to the timing of the wholesale market there are no event notification –related contract changes required to bid Day Of AMP into the CAISO Day Ahead Market. Day-Of notification will be supported without any change in notification. Internal procedures will need to be updated to communicate the availability of the resource.
Evaluate performance risk for proposed PDRs	CBP, AMP	2Q	Assess financial risk associated with performance for proposed PDR bids that informs bidding strategy.
Inclusion of Non-Bundled Customers in bids	All	3Q	The ability to bid in non-bundled customers will require coordination with the appropriate LSE. This drives recommendation to start bidding with Bundled Customers only.
New Supply Side	All	3Q	*Evaluate* the need/value in developing a retail

Table 8 *High-level Action Plan* **Wholesale Market Integration of PG&E DR Programs**			
Item	*Program*	*Timing (2014)*	*Comments*
Program for Wholesale Market Integration			program based on wholesale market requirements that could support the transition of customers who meet wholesale requirements while maintaining those customers who do not and need to be retained for local use. This effort could be in the form of a pilot throughout the bridge funding period. Lessons learned from current pilots and integration activities should be incorporated.
Transition of Specific Customers	All	3-4Q	*Analyze* specific customers (in both low and high compatibility programs) to determine ability to transition to a Supply Side program.
Real-Time and A/S	All	3-4Q	Evaluate the value and complexity to integrate into Real-Time Energy and Ancillary Services markets.
Analyze effort to integrate DBP	DBP	3-4Q	RDRR was originally developed to accommodate economic Day-Ahead energy for emergency programs with multiple program participation. Many BIP customers are co-enrolled in Demand Bidding and have DR capability that can be integrated in addition to emergency capability. Target 2015 for implementation.
Review Lessons Learned	All	4Q	Analyze load impacts, cost effectiveness, etc. for incorporation into further planning efforts.

6 Acronyms and Definitions

Term	Definition
ADS	Automated Dispatch System: Electronically transmits dispatch information to a Scheduling Coordinator
AGC	Automatic Generation Control: Directly controls the output of resources through a signal from the CAISO Energy Management System
CMRI	California Market Result Interface: Publishes system through which various market results are published to Scheduling Coordinators.
DDR	Dispatchable Demand Resource: Demand as a resource that is bid directly into the CAISO market and that can offer all Ancillary Services including regulation.
DLAP	Default Load Aggregation Point: The LAP defined for the TAC Area at which all Bids for Demand shall be submitted and settled, except as provided in Sections 27.2.1 and 30.5.3.2
EMS	Energy Management System: The CAISO internal system that monitors Real-Time grid conditions and determines instantaneous system regulation requirement
FNM	Full Network Model: The CAISO internal database that maps all system loads and resources to specific locations on the grid as well as each resource physical characteristics

IFM	Integrated Forward Market: Market software that co-optimizes the hourly requirements of energy, ancillary services and congestion at the least cost based on schedules and bids submitted by Scheduling Coordinators
Master File	A file containing information regarding Generating Units, Loads and other resources, or its successor
NGR	Non-Generator Resource: Resources that operate as either Generation or Load and can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to do the following on a continuous basis: (1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy
PL	Participating Load: An entity 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.
PDR	Proxy Demand Resource: A Load or aggregation of Loads capable of measurably and verifiably providing Demand Response Services pursuant to a Proxy Demand Resource Agreement.
RDRR	The Reliability Demand Response Resource (RDRR) is a wholesale demand response product that enables compatibility with, and integration of, existing retail emergency-triggered demand response programs into the California ISO market and operations. This includes newly configured demand response resources that have a reliability trigger and desire to be dispatched only under particular system conditions.
RDT	Resource Data Template : A spreadsheet that contains comprehensive operational resource characteristics
RTED	Real-Time Economic Dispatch: Real-Time market algorithm that dispatches energy in economic merit order every five minutes based on short-term load forecast
SLAP	A CAISO defined subset of PNodes within a Default LAP.(DLAP)
SC	Scheduling Coordinator: The type of entity through which CAISO conducts all market related transactions and financial settlement.
SIBR	Scheduling Infrastructure Business Rules: The system and rule set that defines all resource and load bidding and scheduling properties that create a valid bid set for execution in CAISO market software.

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APPENDIX F

OLIVINE REPORT PRESENTATION – APRIL 10, 2014

EX-PARTE HANDOUTS

olivine™

PG&E DR Integration

CPUC Energy Division Update

Beth Reid
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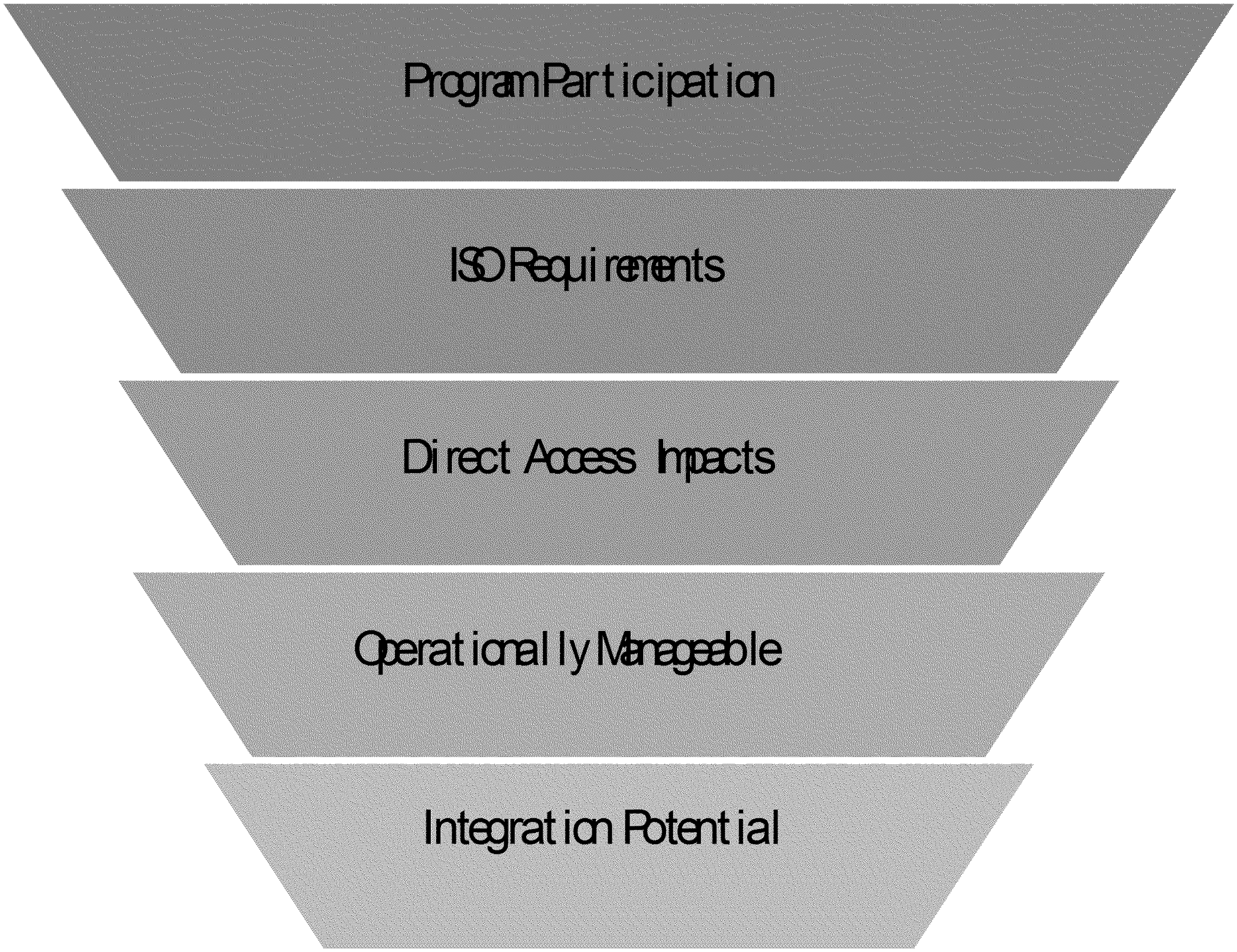
PDR 2014: Process Funnel



PDR 2014: Program Participation

Program Participation
795 MW †

Less Non-Compatible Programs
≅ 355 MW †

≅ 440 MW

- Per Olivine's 2013 Evaluation of PG&E's DR Programs for Wholesale Market Integration, a number of programs are currently incompatible for wholesale market integration.
- Analysis assumes no exceptions to ISO requirements or new revisions to program tariffs

Funnel employs 2013 data. Results subject to revision due to unanticipated future fluctuations in enrollment & nominations
†Based on Ex Post Estimated Load Impacts from PG&E's September 2013 ILP

RDR 2014: Program Participation

olivine™

Program Participation
440 MW †

Less BIP Participation
BIP ≅ 210 MW †

≅ 230 MW

- CAISO RDRR implementation delays
- RDRR not economically dispatched by CAISO market
- Full RDRR dispatch may be required in an emergency

Funnel employs 2013 data. Results subject to revision due to unanticipated future fluctuations in enrollment & nominations
†Based on Load Impacts from 2013 Events

PDR 2014: ISO Requirements

olivine

Remaining Integration Potential
≅ 230MW

ISO Requirements
≅ 90 MW †

≅ 140 MW

- Sub-LAP versus System dispatch, no DLAP option in Wholesale Market
- Minimum load reduction 100 kW
- Maximum resource size 10 MW
- Each PDR must be associated with a single LSE (see next slide)

Funnel employs 2013 data. Results subject to revision due to unanticipated future fluctuations in enrollment & nominations
† From PG&E's April 1st DR Load Impact Filing 2013

PDR 2014: Direct Access Impact

Remaining Integration Potential
≅ 140 MW

Less Direct Access Impact
≅ 100 MW †

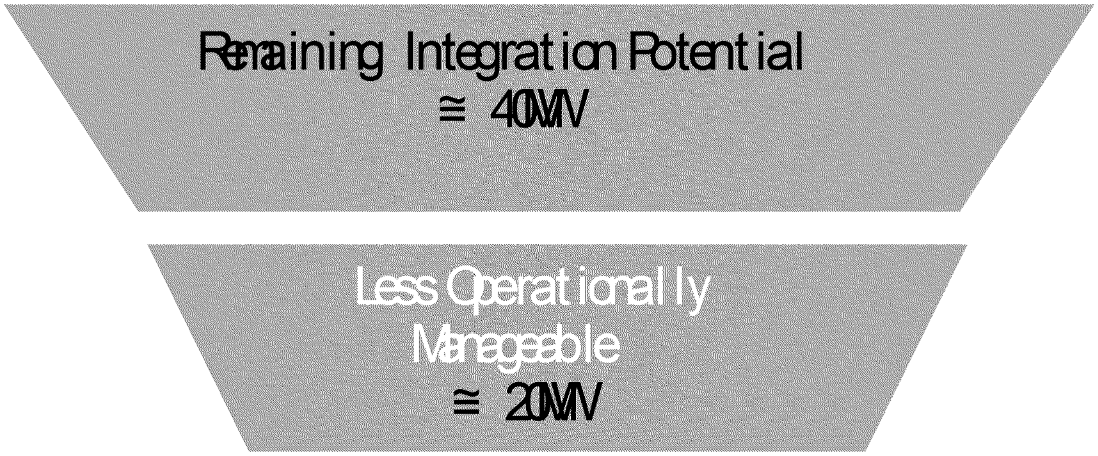
≅ 40 MW

- There are approximately 50 MW of Direct Access Participation in AMP & CBP
- Aggregator Portfolios Co-mingle Bundled and Direct Access
- Approximately 100 MW of Co-mingled participant load in Sub-LAPs with a significant direct access impact

Funnel employs 2013 data. Results subject to revision due to unanticipated future fluctuations in enrollment & nominations

†Based on Load Impacts from 2013 Events

PDR 2014: Operationally Manageable

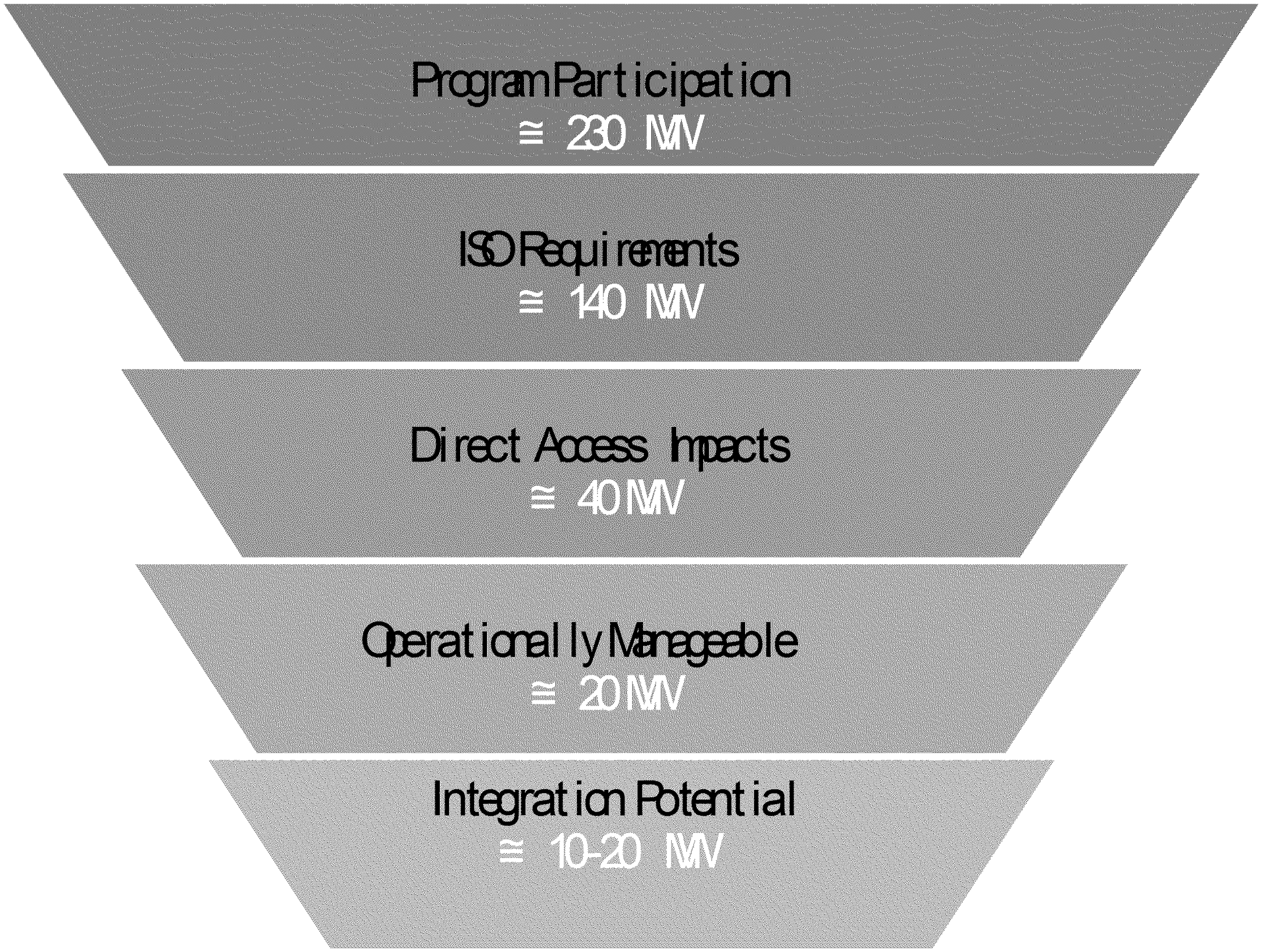


≅ 20 MW

- Only 13 Sub-LAPs contain quantities feasible to register manually
- Registrations and bidding require new workflows with manual processes
- CAISO currently does not have DRS APIs in place
- Bidding all of AMP would require approximately 200 PDRs

Funnel employs 2013 data. Results subject to revision due to unanticipated future fluctuations in enrollment & nominations
†Based on Load Impacts from 2013 Events

PDR 2014: Process Funnel

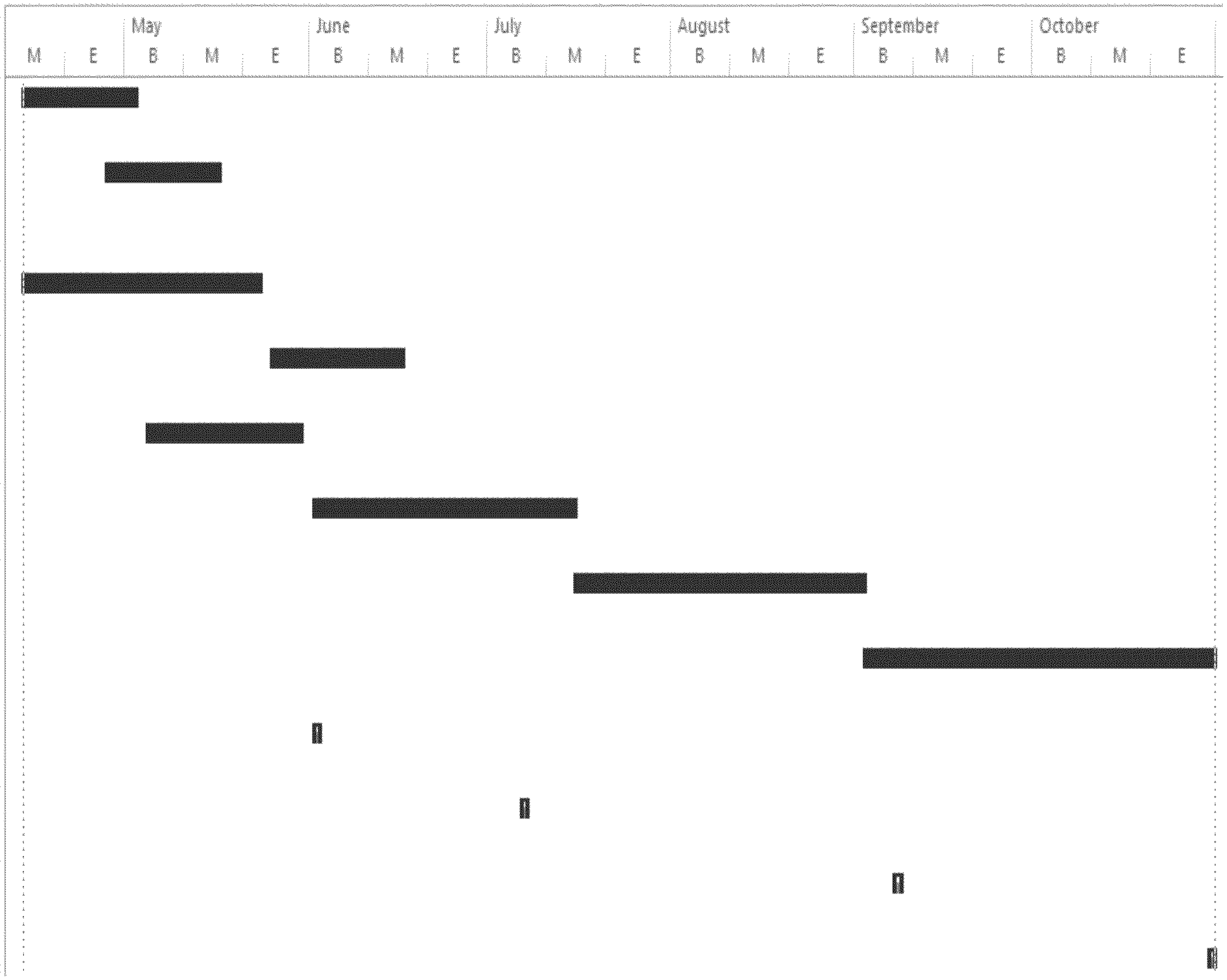


Funnel employs 2013 data. Results subject to revision due to unanticipated future fluctuations in enrollment & nominations

†Based on Load Impacts from 2013 Events

Project Timeline

Task Name	Duration	Start	Finish
Meter Data Process	15 days	Mon 4/14/14	Fri 5/2/14
Determine PDR Shadow Calculation Process	15 days	Mon 4/28/14	Fri 5/16/14
Establish Bidding Process	30 days	Mon 4/14/14	Fri 5/23/14
Establish Notification Process	16 days?	Mon 5/26/14	Mon 6/16/14
Determine Resouce Make Up	20 days?	Mon 5/5/14	Fri 5/30/14
CAISO Registration Process	32 days	Mon 6/2/14	Tue 7/15/14
Initial Market Bidding	35 days	Wed 7/16/14	Tue 9/2/14
Expanded Market Bidding	43 days	Wed 9/3/14	Fri 10/31/14
Tentative CPUC Update 1	1 day	Mon 6/2/14	Mon 6/2/14
Tentative CPUC Update 2	1 day	Mon 7/7/14	Mon 7/7/14
Tentative CPUC Update 3	1 day	Mon 9/8/14	Mon 9/8/14
Tentative CPUC	1 day	Fri 10/31/14	Fri 10/31/14



Next Steps

CAISO Integration: 2015 and beyond

- PG&E believes further upside potential exists in the integration of DR with CAISO markets
  - Efficiency / greater comfort from 2014 experience
  - Access to Direct Access customers via agreements with third-party ESPs (≅ 100 MW)
  - Changes to CAISO business rules (≅ 90 MW; more if you include SmartAC)
  - Implementation of PDR tariff (≅ 210 MW)
- Automation at PG&E and CAISO is needed to capture most of this potential
  - Automation required to manage significant increases in scale (e.g., resource registrations) and complexity (e.g., real-time dispatch)
  - PG&E intends to pursue additional integration opportunities that do not require automation, likely limited to tens of MW
- Automation will require significant investment of time and money
  - Currently estimated to be tens of millions of dollars
  - DR OIR Phase 3 and next DR funding application (November 2015) should guide investment decision