Rulemaking No.: 13-09-011 (DR)

Exhibit No.: JDRP-1

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PHASE TWO AND PHASE THREE OPENING PREPARED TESTIMONY OF JOINT DEMAND RESPONSE PARTIES

(EnerNOC, Inc., Comverge, Inc. & Johnson Controls, Inc.)

Rulemaking 13-09-011
Demand Response (DR)
Phases Two (Foundational Issues) & Three (Future DR Program Design)

May 6, 2014

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I.
EXECUTIVE SUMMARY

This Exhibit JDRP-1 is the opening prepared testimony of the Joint Demand Response (DR) Parties addressing the Phase 2 (foundational issues) and Phase 3 (future demand response program design) issues identified in the "Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scoping and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing guidance for Testimony and Hearings" issued in R.13-09-011 (DR) on April 2, 2014 (Revised Scoping Memo). Exhibit JDRP-1 follows the "Guidance for Testimony" for Phases Two and Three set forth in Attachment A of the Revised Scoping Memo. Specifically, Exhibit JDRP-1 has addressed the issues identified in Attachment A in the required order.[1]

The Joint DR Parties are comprised of three companies, EnerNOC, Inc., Comverge, Inc., and Johnson Controls, Inc., each of which currently aggregates residential, commercial, and industrial customers to participate in a broad range of DR programs managed by grid operators across the United States and the world. In California, the Joint DR Parties have had long experience in participating in DR programs offered by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) (collectively, the Investor-Owned Utilities ("IOUs")).[2]

Over the years, each of the Joint DR Parties has invested a significant amount of effort, innovation, intellectual leadership, capital, and desire for the California DR programs to be successful. In doing so, each of the Joint DR Parties has developed strong, working relationships with the California IOUs and with the customers of the IOUs. Joint DR Parties have also been engaged in California Independent System

[1] Revised Scoping Memo, Attachment A, at p. 1.
[2] Each of the Joint DR Parties is more specifically described in their Joint Prehearing Conference filed in R.13-09-011 (DR) on October 14, 2013.

Operator's (CAISO's) stakeholder processes. These processes have included those to develop Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR) and to consider the ability for DR to participate as a flexible capacity resource in the CAISO's Flexible Resource Adequacy Criteria Must-Offer Obligation (FRACMOO).

Despite these efforts, for various reasons, DR resources have not participated in the wholesale market to any significant extent to date. The Joint DR Parties understand that this Commission and the CAISO would like to increase DR participation in the CAISO markets and that the resource needs on CAISO's system are changing. There is also a desire to increase DR participation beyond the current levels and to utilize DR resources to meet future, long-term procurement needs.

Such goals are good and well intentioned. However, there seems to be a rush to judgment as to whether participation in the wholesale market is going to accomplish those goals. There are many issues that are unresolved. These include: rushing to market without all of the pieces being in place to facilitate a successful transition to the wholesale market, developing a market model that is more complex than is necessary, failing to address market barriers, ignoring whether the market signals are adequate to encourage customer participation, and driving DR participation to behave like a generator. Such circumstances run counter to the goal of promoting DR and jeopardize the resources that have been developed to date.

The Joint DR Parties are not alone in raising these concerns and urging appropriate resolution of these issues. Notably, the DR Collaborative - a broad-based alliance of IOUs, DR aggregators, customers, ratepayer advocates, and environmental organizations have similarly brought these issues to the Commission's attention, especially to achieve the Commission's goal to "enhance the role of demand response in meeting the State's resource planning needs and operational requirements."[3] The Joint DR Parties urge the Commission to be thoughtful and deliberate in the actions it takes to "enhance" DR and ensure that it first has identified a reasonable plan and path forward to do so. That path must be defined by clear, understandable, rational and

[3] Revised Scoping Memo, at p. 1.

contain reasonable rules. The path must also allow for parties, including the Commission and the CAISO, to learn from the inevitable mistakes that will happen and to make corresponding adjustments. The path must start simply and work toward progressively more complex products.

In summary, by Exhibit JDRP-1, the Joint DR Parties recommend that the Commission adopt and/or consider the following on the issues being addressed in Phases Two and Three of this proceeding:

***PHASE THREE:* <u>*Demand Response Goals*</u>**

1. Develop achievable DR goals, which should be based on 5% of peak, local and flexible demand, and require the IOUs to demonstrate their progress toward achieving those goals in their annual RA compliance filings.
   a. Utilities should promote DR to their customers and provide incentives for customer representatives to promote DR and to have a high percentage of DR participation among their customer accounts.
   b. Integrate DR into utility procurement planning processes, such as has been done for SCE and SDG&E in D.14-03-004.
   c. Create stable rules for resource adequacy.
   d. Reduce regulatory uncertainty.
2. Encourage DR participation.
   a. Eliminate excessive and punitive payment structures in favor of structures that are more aligned with how other resources are paid.
   b. Eliminate per event performance evaluation and expand the evaluation of performance to coincide with the commitment period of the resource.
   c. Examine measurement methodologies to give full credit for delivered performance.
   d. Rationalize the number and variety of programs, and the amounts these programs are paid, to be consistent with the value provided and that value should be recognized for cost-effectiveness purposes.

e. Require local deliveries only when system conditions or economics dictate; otherwise, if the resource is being dispatched more broadly, settle the resource on the same basis as it is dispatched, either on a single sub-LAP basis or across all sub-LAPs within a utility service territory.

f. Overly complex rules translate into higher costs and higher risk of providing the service which, in turn, reduces the pool of customers that will be invited to participate in DR programs. This is counter to the Commission's goals.

g. Customer recruitment, enablement and payment processes take too long.

***PHASE THREE:* <u>*Resource Adequacy Concerns*</u>**

1. The path to success for DR Resources through wholesale market integration is unclear.
2. The rules that would apply to DR resources that participate in the wholesale market for RA purposes, and are, therefore, eligible for a capacity payment, have not been settled and may take longer than expected to achieve FERC approval.
3. Energy prices are low in many hours.
4. Local dispatch and settlement requirements are costly, complex and inefficient.
5. Telemetry requirements are not resolved and could be more onerous than is required in other markets.
6. A must-offer obligation is not an efficient method of dispatching DR and introduces after-the-fact reasonableness concerns. Instead, DR should be dispatched when system conditions, or economics, dictate it is beneficial.
7. When not needed for transmission and reliability purposes by CAISO, the IOUs should be able to utilize a resource for distribution level needs.

***PHASE THREE:* <u>*CAISO Integration Costs*</u>**

1. DRPs will incur a significant amount of initiation costs to establish the ability to participate in the wholesale market.
2. While the categories of cost are largely consistent across markets, the magnitude of the costs varies by each market's specific requirements to participate.

3. CAISO's market participation rules will result in higher participation costs than other markets, like PJM and ERCOT. The factors that will drive higher market participation costs include:
    a. Data requirements for both operational and settlement purposes
    b. Telemetry requirements
    c. Local delivery requirements, especially if accompanied by a must-offer obligation
    d. The above-referenced factors will increase customer engagement costs.

PHASE THREE: <u>Supply Resources Issues</u>

1. The requirements that a DR supply-side resource would have to meet may make or break the success of the integration of DR resources into the wholesale market.
2. The resource characteristics are under-development at both the CAISO and CPUC and are therefore unsettled and in flux. Wholesale market participation cannot occur until the product requirements are established in a manner that permits the resource to participate in the market consistent with the resources characteristics.
3. Resource adequacy proposals are tied to a must-offer obligation, which is not a good mechanism for DR resources.
4. DR resources should not be required to behave like a generator.
5. Just because DR programs could participate in the wholesale market, does not mean that they should. There are other factors to consider.
6. The DR Auction Mechanism (DRAM), as proposed, contains several elements that are concerning or problematic, in particular, the "pay-as-bid" approach, subject to an administrative cap, and the failure to provide any meaningful information as to the results of the auction.
    a. There would not be a single price paid for comparable resources, and no one would know what price was paid for the resources selected. Therefore, there is no market information as to the value of the resources.
    b. An administrative cap could disqualify resources that are providing a higher value to the system in favor of resources that provide a lower value to the system.

c. It is unclear how resources, with very different operating characteristics, would be solicited through one auction mechanism, such as local, system, or flexible RA capacity.

d. The attributes that define the availability and dispatch requirements of the resource would not be standardized, thereby resulting in, potentially, a wide variation in bids among resources based upon differences in those characteristics.

e. The Demand Response Provider (DRP) should not be required to demonstrate that it has customers to support the bid capacity at the time of the auction, particularly, if the auction is well in advance of the delivery period.

f. A DRP should have the ability, through true-up auctions held closer in time to the delivery period, to adjust its position.

g. Annual and seasonal auctions make sense, although the months that comprise a season should be shorter to allow for different delivery capabilities in different months.

h. There are lessons to be learned from the experience in other markets.

i. It is not appropriate to adopt the Pacific Gas and Electric Company (PG&E) performance matrix and apply it to resources that are participating in the wholesale market.

j. If the utility is soliciting supply-side resources through a self-administered process, like the DRAM, it should not be a participant in providing those services.

PHASE THREE: <u>Load Modifying Resources</u>

Load modifying resources are DR resources that are not bid into the wholesale market; therefore, load modifiers can be either resources that are exposed to rate changes through utilities tariffs or are dispatchable based upon system conditions. Utilities are likely to be the most significant, if not the exclusive, provider of these services.

PHASE THREE: ***<u>Program Budget Cycles</u>***

To the greatest extent possible, DR should be incorporated into the procurement processes of the utilities, which provide for longer budget cycles than DR has traditionally had, which is a maximum of 3 years, and sometimes longer if bridge funding is provided.

PHASE TWO: ***<u>Back-Up Generators</u>***

The Joint DR Parties' positions on this issue are included in their Joint Response on Phase 2 Foundational Questions and Joint Reply to Responses to Phase 2 Foundational Questions filed in this proceeding (R.13-09-011 (DR)) on December 13, 2013, and December 31, 2013, respectively, and are part of the formal record of this proceeding.

PHASE TWO: ***<u>Cost Allocation Mechanism</u>***

The Joint DR Parties take no position on this issue at this time.

II.
PHASE THREE ISSUES

A. DEMAND RESPONSE GOALS

Q. A1. Please explain what DR "goals" have been and are currently in place for the IOUs.

A. A1. Today, there is *a* DR "goal" in place, but, it is not a goal that provides any meaningful measurement or incentive for increased DR program load impacts or participation. Specifically, the Commission, jointly with the California Energy Commission (CEC) and, initially, the Consumer Power and Conservation Financing Authority, adopted the Energy Action Plan (EAP) I in 2003, EAP II in 2005, and the EAP Update in 2008, which, among other things, established the "'loading order" of energy resources that will guide decisions made by the agencies jointly and singly."[4] The "loading order" "identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs" and "[a]fter cost-effective efficiency and demand response," renewable sources of power and distributed generation are then to be relied upon to meet need with efficient fossil-fired generation to be used "[t]o the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs."[5] This "loading order" has not only been followed by the Commission in its Long Term Procurement Planning (LTPP) process, but is also embodied in legislation that requires the IOUs to procure all available energy efficiency and demand response that is cost-effective, reliable, and feasible.[6]

As part of the EAP, the Commission set an aspirational goal, for demand response to represent 5% of peak demand in the California. In actuality, the amount of demand response achieved by the IOUs is half of that goal, or approximately 2.5%. However, the Commission has stopped short of

4 EAP, at p. 4.
5 EAP II, at p. 2.
6 Public Utilities (PU) Code §454.5(b)(9)(C); see also, Decision (D.) 14-03-004, at pp. 6-7, 12-16.

implementing a specific goal, against which utility progress in achieving that goal is measured.

Q. A2. Has this "aspirational goal" been achieved or effective in increasing demand response?

A. A2. No. In actuality, the amount of demand response achieved by the IOUs is half of that goal, or 2.5%. Further, the Commission has stopped short of implementing a specific goal, against which utility progress in achieving that goal is measured. It is this lack of enforceability that has undermined the "goal" and made it suboptimal as a means of increasing DR.

Q. A3. Please explain.

A. A3. When the Commission establishes a goal for the utilities to achieve, and the utilities progress toward meeting that goal is measured, the utilities marshal their internal efforts to achieve the goals established by the Commission. If those goals do not exist, and there is no measure of success or failure, or consequences for failure to achieve the goals, then the goal is hardly more than words on a paper. If there is no measure of success or failure, then the status quo will remain. For example, state law has required that the utilities acquire 33% of their resources from renewable sources. The utilities have put into place, with direction from the Commission, processes to achieve that requirement. In addition, the utilities are measured in their progress toward achieving that goal. In addition, the utilities have been given specific energy efficiency targets, against which their progress is also measured. As a result, the IOUs have established internal processes, personnel and departments to achieve these goals.

While the IOUs have dedicated personnel to their demand response programs, and the utilities are invested in making these DR programs succeed, the success of these programs is not measured by the total achieved capacity relative to the IOUs' overall resource needs or a specific reduction to its peak demand. A measureable goal will encourage the IOUs to put into place internal processes to direct its efforts toward achieving the goal, thereby looking for ways to expand demand response opportunities.

If the success of the DR programs is converted into success for the employees responsible for the programs and the success of the utility, then the incentives, both internally and externally, are aligned. Once a measurable goal is established, then the utility must adopt a cultural that supports achievement of the goal. There exist some "cultural" barriers within the utility in accepting third party DR providers, especially where there is direct customer contact. Some of the customer account representatives, who have had long-standing relationships with its' commercial and industrial customers are suspicious or resentful of the insertion of a third party into, what had been, an exclusive relationship with the customer. Working on replacing the suspicion and a sense of competition with cooperation and mutual success would be a winning combination for all of the parties involved, including the customers. Mutual success, for the utility account representative, could take the form of an incentive for increasing demand response penetration with its' assigned accounts.

The utility could be more of a partner in driving customers toward DR options, thereby helping to reduce customer acquisition costs. For example, without endorsing any specific company, the utility could encourage customers to incorporate demand management services into the customer's energy management strategy, including identifying DR aggregators that are providing services in the IOU's service territory, pursuant to either a utility contract or who is eligible to participate in the wholesale market.

Q. A4. Are there other reasons why increases in demand response and program participation have not been realized?

A. A4. Yes. These reasons include the following:

First, DR has not been integrated into procurement planning and has been separately procured until the recent Commission Decisions in the Track 1 (D.13-02-015) and 4 (D.14-02-033) in the 2012 Long-Term Procurement Proceeding (LTPP). DR has been treated as a resource separate from all other resource procurement. The lack of integration has meant that the Commission has not required that new resource procurement needs be met with, or offset by, demand response resources, either on a current or future basis. Despite the fact that the EAP II (2005) identified this need for integrating demand response into the resource planning activities of the IOUs, the Commission, the CEC and the CAISO, there is still significant room for improvement among the state agencies in achieving this goal. As a result, DR resource options have not, until very recently, been evaluated on a side-by-side basis with other supply resource options. In addition, the assumptions made for DR resource growth, for planning purposes has not been consistently utilized for long-term planning purposes as between the agencies with forecasting and planning responsibility. While the agencies are working to increase the coordination among them, the assumptions err on the side of being conservative, despite very bullish policy proclamations on the desire to increase DR penetration, through various means.

Second, there has been a great deal of uncertainty over the future course of DR services offerings in the State for a number of years that has stalled program growth. While, the Commission has clearly articulated a desire to integrate DR resources into the wholesale market,[7] the manner of that integration, the timing and the continuation of retail programs was unknown. For third-party aggregators, there was uncertainty as to the whether the utility relationship would continue and similar uncertainty was expressed by the IOUs. Therefore, it was difficult to have a sense of knowing in what direction DR was headed in the State, until the loss of SONGS raised the desire for increasing DR resource penetration and availability.

The regulatory process has been disruptive to program continuity because of the long regulatory processing time for applications and contract approvals, short time allotted for program implementation, contract solicitations and negotiation cycles, and shifts in emphasis from program year-to-program year. There has

[7] D.12-04-045, at pp. 13-16; D.09-08-027, at pp. 30-31.

been a failure to appreciate how these shifts, and alternating accelerations and delays affect the aggregator or the customer.

Third, resource adequacy requirements for DR resources are, and have been, in flux. The primary benefit ascribed to DR by the IOUs has been the ability to meet or reduce the RA requirements, for which DR is currently being used, to meet or reduce the system and local RA requirements of the IOUs. However, RA is actively being examined both by the CAISO in its Reliability Services Initiative (RSI) and by the CPUC in its current RA Docket (R.11-10-023). Therefore, there is uncertainty as to how DR will count for RA, or, more directly, what the resources will be required to do in order to count for RA going forward. These requirements will define the obligations the DR resource must meet in order to qualify for RA either through its participation in the wholesale market or as a retail resource. Until these rules are solidified, in a manner that is consistent with the capabilities of the resource, then resource development will be at a standstill. The areas under development for DR resources include RA requirements for system, local or flexible resources.

Q. A5. How would you suggest that DR participation could be increased over current levels?

A. A5. DR resources have been developed more from a position of protecting against gaming than from a position of encouraging customer participation. Protection against gaming is important; but, there should be a balance in the program rules so that customers are acknowledged for the contributions they are making to reducing demand on the system. If there is evidence of manipulation, then there should be consequences for the action. But, the current rules inhibit growth and customer participation.

Q. A6. Can you detail what aspects of current program design that discourage customer participation??

A. A6. Yes. The following design features discourage customer participation:

(1) First, if the DR resource fails to achieve 90% performance, the current structure severely penalizes the DR aggregator and, therefore, the customer,

not by penalizing the shortfall, but by confiscating payment on the delivered capacity. For example, if an aggregator had a 100 MW capacity commitment, and on a single event, delivered 89 MW, the DR aggregator is not penalized on the 11 MW shortfall. Instead, the aggregator will lose 50% of its compensation for the delivered capacity, and only be compensated for 44.5 MW.[8] This is a severe and punitive, per-event confiscation of revenue for the aggregator. However, the IOU and its ratepayers receive 89 MW of DR capacity and only pay for half of it. No other resource would survive, much less grow, under such a punitive system. If it is the desire of this Commission to encourage and grow DR resources, to increase the utilization of the resources and to integrate DR resources into the wholesale market, then the incentives and disincentives for performance and payment must be more in line with those of other resources. Later, in this testimony, a specific payment proposal will be offered, which takes into consideration those employed by the CAISO for other resources, as well as those employed by other markets.

(2) Customers, and aggregators, should be recognized for the performance that is delivered. Many customers have declined to participate in demand response programs because the performance they provided, which can be demonstrated and measured, was not recognized by the baseline methodology and, therefore, the customer was not compensated. If customers take action to reduce demand on the system and that performance is not recognized, customers will decline to participate.

Performance is based upon a single baseline methodology, a 10-in-10 average of non-holiday, weekdays, with an elective +/- 40% day-of adjustment. The day-of adjustment is supposed to be a proxy for weather sensitive load. A significant portion of DR resource capacity, in the summer, is related to air conditioning load and is, therefore, highly weather sensitive. In addition, some loads, particularly manufacturing loads, are highly variable based upon production schedules, such that a 10-in-10 day average is not

[8] This structure is in place in SCE's service territory; but, it has been modified in D.14-02-033 for PG&E.

representative of the resource's capacity on any given day. Event performance is not weather normalized. Events can be called on "cool" days and DR performance, that is weather sensitive, will be less on cooler days than warmer days.

Other markets allow for a choice of baselines. CAISO has indicated a willingness to explore alternative baselines This should be explored.

(3) Rationalizing the services that DR resources will provide and aligning the attributes of the resources with the compensation provided would be an important outcome of this proceeding. DR programs were developed by the utilities, first, and then third-party aggregators were invited to participate in providing services alongside these pre-existing utility programs. Some DR programs have been in existence for decades and were designed to address the system conditions that were prevalent at that time. As a result, there are various "flavors" of DR offerings available on a side-by-side basis. While these varieties of DR give customers a range of options, it is also difficult to attract customers into a program, with an aggregator, if the customer can "do less" and get paid more. As the "supply-side" resource definitions are developed, it would be important to determine whether the IOU is a solicitor, only, of such resources, or if the IOU is also a provider. In addition, achieving a hierarchy of DR capacity value, along a spectrum, based upon the value of the services provided, would be an important outcome of this proceeding. This value should be recognized in the cost effectiveness methodology. Many of the attributes that DR resources are being asked to provide are not included in the cost effectiveness methodology and, therefore, are not recognized in contributing any benefit in the calculation.

(4) Because Proxy Demand Resource (PDR) requires a DR resource to bid, perform and settle on a sub-LAP basis, there is no opportunity for a DR resource to offer system services that could be delivered, and settled, over a larger geographic area, like a Default LAP (DLAP). System and flexible RA are not required to be delivered on a local basis and LSEs could procure RA

resources anywhere in the system to meet these requirements. The nature of DR resources is that they are distributed across a utility's service territory. If DR resources had the ability to aggregate across a DLAP, the size of the resource would increase and the performance risk that the aggregator would face in order to deliver the resource across a larger geographic area would decrease. Nonetheless, DR resources must deliver on a local basis, irrespective of whether the attributes of the resource necessitate a local delivery. The requirement for a local delivery is dictated by the design of PDR.

Local deliveries are more difficult to manage due to a smaller resource base, and less diversity of customer loads, which is an important component of aggregation. Aggregation mitigates the risk of performance of any single customer or customer type. Requiring local deliveries at all time, even if system conditions do not require it and even if the resource attributes do not require it, significantly reduces the risk mitigation that aggregation, across a larger group of customers and geographic areas, provides.

Other markets allow for DR resources to deliver across larger geographic areas unless the system conditions require local deliveries. This is true in PJM and ISO-NE. In ERCOT, delivery is required on a large "zonal" basis – with 4 zones covering the entire state.

PJM provides for registration and aggregation by transmission utility zone, the equivalent of a DLAP in California. This has helped establish a robust demand response presence. PJM currently has the ability to request local dispatch on a zip code basis and will establish measurement and verification (M&V) obligations beginning in 2015. Non-performance penalties are reduced for such local dispatch.

Philosophically, sub–LAP delivery and settlement requirements ought to be required only when the system conditions require it, such as when the transmission constraint is controlling, rather than as a general proposition. Sub-LAP delivery is also not consistent with the way in which local resource adequacy is defined. Local resource adequacy requirements are determined on a local capacity area (LCA) basis. While PG&E has several LCAs, the CPUC has condensed the number of LCAs into 2, for purposes of meeting the local RA requirement: Greater Bay Area and "Other PG&E".[9] In other words, the CPUC allowed LSEs to aggregate the resources they had acquired across several of the smaller LCAs in order to meet the local RA requirement. The aggregation was necessary to address local "market power concerns".[10] DR resource adequacy requirements and delivery requirements should be no more onerous than other resource types and should reflect the capabilities of the resource. Therefore, local dispatch should only occur when the system requires it and compensation mechanism should reflect the additional value of the local resource.

If there is no price variation across the sub-LAPs, and multiple sub-LAPs are being dispatched at, or near, the same price, then the resource should be measured and settled across all dispatched sub-LAPS instead of requiring settling on an individual sub-LAP basis. When multiple sub-LAPs are dispatched, even though the resource has the ability to be dispatched on an individual sub-LAP basis, the resource is being used like an aggregated resource, across several sub-LAPs, and should be settled on a basis comparable to how the resource is being used. If there is no physical or economic reason to dispatch an individual sub-LAP, then there is no rational reason to require sub-LAP dispatch and settlement. Therefore, if one sub-LAP is dispatched, then performance, and settlement, should be based upon that one dispatched sub-LAP. If multiple sub-LAPs are dispatched, then the performance of the resource should be measured across the dispatched sub-LAPs.

(5) Because of the aforementioned issues, punitive penalty structure, restrictive performance measurement, multiple competing programs and a local delivery requirement, the risks of providing DR resources in California are

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[9] D.10-06-036, at pp. 17-18.
[10] Id.

comparatively high, thereby increasing the cost of providing resources in California. In order to manage these risks, customers are selectively invited into an aggregator portfolio only to the extent the confidence in the customer's performance is high. This evaluation increases the cost of the customer recruitment process, because the aggregator cannot afford to accept all interested customers into the portfolio. Aggregators must turn willing customers away if the customer's performance could jeopardize the performance of the portfolio. The risk is too high to accommodate all but the best performing customers. As a result, the ability to grow the DR resource under these conditions is seriously hampered. Therefore, these policies, in combination, actually reduce the number of customers that participate as DR resources rather than increase it.

Additionally, the amount of program management required to ensure customer performance is increased and the amount of performance recognition, and therefore, revenue received is less. Higher costs and lower revenues is not a recipe for successfully growing the DR resource.

(6) Customer enrollment and enablement process and payments for deliveries take too long to resolve.

Q. A7. Do you believe that DR integration into the wholesale market will be successful?

A. A7. I do not think that integration into the CAISO wholesale market, as currently envisioned, will expand DR participation beyond its current levels and could reduce DR participation.

Q. A8. Please explain the basis for your opinion.

A. A8. There are several reasons why I do not think that integration of DR resources into the wholesale market will result in an expansion of the current penetration of DR resources in the State. The opportunity for DR to participate as a resource in CAISO is as an energy or ancillary services resource. DR is, primarily, a capacity resource. It is not utilized to produce energy across a large number of hours per year. DR is used to reduce demand during times of high demand or high prices to provide a cost-effective, supplemental resource to the grid for reliability purposes. DR resources are generally dispatched for a short period of time for a few days per year. However, DR resources are generally paid as a capacity resource for the availability they provide to the transmission system to be dispatched when needed. :

(1) *There is an unclear and uncertain path to a capacity payment for a DR resource that participates in the wholesale market.* The Commission is currently exploring that path in this docket through the Demand Response Auction Mechanism (DRAM). In other organized markets, there is a centrally-administered capacity market/auction that is administered by the wholesale market operator, where capacity is treated as a separate service. The uncertainty over the path to a capacity payment puts the entire success or failure of the wholesale market design for DR resources into question. Without a separate, centrally-administered capacity market, DR Providers must rely, primarily, upon the utilities for a capacity payment. The options would be thus:

   a. Either DR Providers will obtain a capacity payment from an LSE through a bilateral contract in exchange for the DR Provider making a capacity commitment to the utility, that will contribute toward meeting the LSE's resource adequacy requirement, as is done today, or

   b. The LSE could solicit resources through an RFO as is done today, or

   c. The DR Provider would have to participate in some quasi-market construct, like the DRAM.

(2) *Energy prices are low in most hours.* Therefore, there is no energy market signal that DR resources are needed. As a general statement, DR resources will not participate in the market at the levels at which energy prices are clearing in most hours, which is slightly more than $50/MWh. DR resources are prohibited, by the Commission, from bidding into the wholesale market

below the net benefits test (NBT) threshold.[11] CAISO calculates the NBT threshold for May 2014 to be \$65.35/MWh on-peak and \$67.86/MWh, off-peak.[12] CAISO has also calculated that peak, day-ahead average marginal prices, over the course of 2013, were between \$38 and \$55/MWh.[13] There are likely to be many hours when the NBT exceeds the local marginal price in many hours. A \$50/MWh price is not a signal to a customer that a reduction in its demand on the system is needed. In fact, this price indicates that there is plenty of energy on the system. It should not be expected that DR resources will clear in all or most hours, when prices indicate that energy is plentiful. CAISO has also indicated that energy prices exceed \$250/MWh in less than 2% of the hours.[14] Again, in most hours, the prices at which energy clears in the wholesale market does not indicate that DR resources are needed.

(3) *Requirements for DR resources to bid, dispatch and settle on a sub-LAP basis, at all times, increases the complexity of participating in the wholesale market.*

(4) *There is uncertainty regarding telemetry requirements.* CAISO requires telemetry for resources providing energy if the resources is 10 MW or larger and for all ancillary services. No other market requires telemetry in order to provide energy and telemetry is not required to provide spin and non-spinning reserves in MISO, NYISO, ISO-NE or PJM.

(5) *There is a risk of after-the-fact reasonableness review over DR resource bidding behavior.* For those 3RD party DR providers that choose to participate in the CAISO market, they must bid the resource so that it is available to the CAISO when it is needed but balance that availability against protecting the resource from being "over" dispatched in hours when the CAISO has

[11] D.12-11-025, Ordering Paragraph 1, at p. 67.
[12] CAISO Monthly Demand Response, Net Benefit Test Results, May 2014, at p. 2. See Appendix A hereto.
[13] CAISO Q4 2013 Report on Market Issues and Performance, February 10, 2014, at p. 12. See Appendix A hereto.
[14] Id., at p.15 (as included in Appendix A hereto).

adequate resources available to it. This is a significant difficulty given the unpredictability of those system conditions and CAISO market prices.

There are many elements that influence market prices. First, relatively high energy prices do not necessarily signal the need for "capacity," though depending on what DRAM auction winners bid into CAISO energy and ancillary services markets this capacity will be called upon. For example, high market prices may be the result of high gas prices, which his unrelated to whether there is adequate capacity available to the system. Second, electricity market price increases are not very predictable, making it all but impossible to enable an expected outcome for the 3rd party that bids into the CAISO markets, or the CAISO. Third, this confounding of energy and capacity availability, without predictability, suggests valuable DR capacity will be used indiscriminately, in essence wasted, and then may not be available when needed. And fourth, the DRAM and RA rules require DR capacity to be available for a minimum of 4 hours for three consecutive days; thus, this RA requirement may result in CAISO deciding to dispatch DR in 4-hour blocks, as opposed to dispatching DR as required to meet the need on the system, for shorter periods of time.

In addition, customer's opportunity costs to curtail vary by customer and vary by day depending upon what is happening at the customer's facility. These are difficult to evaluate. Therefore, the DR Provider's bidding strategy may be subject to scrutiny if the resources are not dispatched at times when they could provide a benefit to the system, based upon the DR Provider's bids, because it is impossible to determine when the market clearing prices will indicate when the resource is needed. As such, it is better to use market conditions as a basis for dispatching the resources, much as is done by the IOUs in their programs today, than to use a must-offer obligation and market clearing prices as a proxy for system conditions.

For all of these reasons, an uncertain path to a capacity payment, low energy prices in most hours, uncertain telemetry requirements, risk associated with DR bidding strategies, DR aggregators are not likely to run headlong into this market until the uncertainty of the market rules is removed and there is an apparent, economic opportunity. As a result, in the near-term, the only likely penetration into the wholesale market will be by the utilities bidding their retail DR programs into the wholesale market, as those programs already have RA value established and the IOUs do not need to receive a capacity payment for its participation, if they have RA credit.

CAISO has indicated that it will provide "exemptions" to some of its market rules in order to facilitate DR resource participation by the IOUs. However, the need for rule waivers is another sign that the existing rules and requirements are difficult to navigate and require changing.

While there is value in understanding "how" to participate in the wholesale market and to gaining experience with it, the cost of the "experiment" is not insubstantial and would only warrant exploration to the extent there was perceived benefit to the aggregator and end-use customers for doing so.

Q. A9. Please explain how you believe a goal should be formulated and how and when success against that goal should be measured?

A. A9. To start, the Commission could establish a goal of meeting 5% of the peak demand, on a system and local basis, with dispatchable, DR resources. These resources could be either load modifiers or resources that are bid into the wholesale market. The 5% local requirement is actually modest, considering that the Commission has designated a very significant amount of new resources to come from preferred resources, including DR.[15]

There are other types of services that DR resources are going to be asked to provide, such as flexible capacity, economic DR and ancillary services. To the extent that DR resources participate as flexible capacity resources in the wholesale market, the CAISO's FRACMOO Proposal provides an opportunity for DR resources to participate as Category 3 resources.

[15] D.13-02-015, Ordering Paragraph 1 at pp. 130-131; D. 14-03-044, Ordering Paragraphs 1 and 2, at pp. 141-144.

Under the current market conditions, described above, there is no basis to reasonably assume that economic DR will be very attractive in California for the near term. The market prices for electricity, based upon the CAISO's quarterly market analysis, does not demonstrate that energy prices will rise to the level that would encourage DR participation. Since it takes time to implement goals and to achieve them, once DR goals are established, the IOUs should establish a plan to achieve the goal within a specified timeframe.

Q.A10. Could you elaborate on how this goal would be measured?

A.A10. Measurement of progress toward achieving the goal could be determined based upon the annual resource adequacy compliance filings. The Commission would know what the IOUs local, system and flexible resource adequacy requirements are and whether 5% of these requirements was met by dispatchable, DR resources.

B. RESOURCE ADEQUACY CONCERNS

Q. B1. How is resource adequacy for DR resources currently determined?

A. B1. RA for DR resources is currently determined by using the Load Impact Protocols (LIP).

Q. B2. How is RA for DR resources proposed to be determined in the future?

A. B2. DR resources that are "load modifiers", which means they do not participate in the wholesale market will reduce the LSE's RA requirement, but will not count as a supply-side resource for meeting the LSE's RA requirement. Only DR resources that participate in the wholesale market will count toward meeting the LSE's RA requirement.

Q. B3. Is this a change from the current convention?

A. B3. Yes. Up until now, resources that were "dispatchable", which included BIP, CBP, and AMP were counted as "supply-side" resources in "meeting" the LSE's RA requirement, while non-dispatchable resources, like coincident peak priding (CPP) and peak-day pricing (PDP), reduced the LSE's RA requirement, but were not considered as a "supply" resource.

Q. B4. What are your concerns with the change in convention that is proposed?

A. B4. Current supply-side resources, unless they are bid into the wholesale market, will be treated like a load modifier. In other words, programs that are currently dispatchable by the IOUs will be treated as being no different, operationally, than a CPP tariff. It is only the factor of being integrated into the wholesale market, not the characteristic of the resource, which will determine whether the resource is a supply-side resource or a load-modifier. But, the main concern is that the Commission not value, more highly, supply-side resource than load modifying resources.

Q. B5. What is the value of a RA requirement?

A. B5. Fundamentally, resource adequacy is the availability of adequate resources to meet system needs at particular times. Generally speaking resource adequacy is only a concern during extreme weather events, transmission constraints, or unexpected power plant outages, all of which can be extremely difficult to predict or price accurately. Of late, the CAISO has identified other concerns wherein the adequacy of resources will be important. That is to ensure that adequate capacity is available to the system when wind and solar resource cycle through their availability on a daily basis.

Resource adequacy has been designed primarily to meet peaking requirements, plus a reserve margin, or local requirements where transmission constraints exist. The availability of RA resources, where and when needed, is the basis for providing these RA resources with a capacity payment.

Q. B6. How do DR resources contribute toward RA?

A. B6. DR resources contribute to resource adequacy by meeting the peak demand needs on the system, which occur infrequently. In that way, building or buying incremental generating capacity in order to meet those few hours of need is deferred and ratepayers have a more cost-effective resource than a lumpy capacity resource addition, for which load must grow to fully utilize over time.

Q. B7. Is this a reasonable use of DR resources?

A. B7. Yes.

Q. B8. How is the use of DR resources expected to change in the future?

A. B8. As described above, there is an expectation that DR resources will be integrated into the wholesale market and subject to a must-offer obligation (MOO). In addition, there is an expected need for flexible capacity resources, which will be needed outside of peak demand periods and necessary for balancing the demand and resources on the system relative to the availability of wind and solar resources. Resources that participate as flexible capacity resources will be subject to a MOO, under CAISO's FRACMOO Proposal.

Q. B9. Do you also have general concerns regarding a must-offer obligations?

A. B9. Yes. A MOO ensures that resources are available to meet the requirements of the system. A MOO is there for resources that generate electricity to ensure that the resource offers its electricity into the energy market. But, a MOO is also there to ensure that resources do not withhold their availability from the system, to artificially create scarcity and to drive up prices.

DR resources are not generators and do not, and cannot, produce energy over long periods of time such that the withdrawal of DR resources would create an artificial scarcity event and drive up prices. To the contrary, DR resources are there to respond to scarcity events, to moderate prices, to relieve stress on the system once it occurs or is imminent. Therefore, a MOO for DR resources simply requires the DR resource to go through a lot of bidding, when the resource is unlikely to be dispatched in most hours. Instead of a MOO, system conditions could be established by the CAISO such that the resource would be required to be available when those conditions occur.

In PJM, for example, the system operator determines when the resources are needed, as opposed to requiring the resource to bid into the market every day. This proposal should be considered as a replacement for a MOO, which carries with it all of the operational concerns that have been discussed in the previous section.

Q.B10. Is the CAISO proposing a MOO for flexible and other RA capacity?

A.B10. Yes. CAISO has proposed a MOO for flexible capacity through its FRACMOO Proposal. In addition, through the RSI, CAISO is proposal a system and local MOO for PDR and non-generator resources (NGR). FRACMOO requires a DR resource to bid into the wholesale, day-ahead and real-time energy markets during a five-hour availability window and to be available to be dispatched up to three hours, when called, for a maximum of five times per month. The MOO being proposed in the RSI would require DR resources to submit day-ahead and real-time energy bids on non-holiday weekdays during the peak hours of 2-6 PM from April to October[16] and 5-9 PM in all other months. These resources must also be available for at least 5 days per month. Through the RSI process, self-schedules are permitted; for FRACMOO, self-schedules are not permitted.

Q.B.11.Do DR resources count toward the LSEs local capacity requirement (LCR)?

A.B.11.Yes. Today, dispatchable DR resources, that are capable of being dispatched on a local basis count toward local RA. However, the ability for DR resources to meet local capacity requirements (LCR) has been the subject of debate within the 2012 LTPP. CAISO was reluctant to count DR resources for local reliability needs for several reasons:

(1) The location of the resource within an LCA was not clear,

(2) The resource could not be dispatched in time to allow the CAISO to stabilize the system after a contingency event;

(3) The resources availability to the CAISO was limited.

Decision (D.13-02-015) directed the CAISO and SCE to work together to develop a definition for DR to qualify as a local capacity resource. That definition has been proposed as part of the 2013/14 LTPP, but has not been fully explored and has not been adopted by the CPUC. Therefore, the issue around DR qualifying as a LCR is being examined in the RSI, but is uncertain and in flux.

In the most recent aggregator-managed portfolio (AMP) contracts, which resulted from D.12-04-045, the DR resources were directed to be locally dispatchable if they were going to count for local RA. The IOUs and the DR Aggregators went to great effort to ensure local delivery for resources beginning in 2013. However, as stated previously, those ability may not fully satisfy CAISO's criteria for DR resources to satisfy the LCR

[16] Of note, the Commission requires RA resources to be available from 1-6 PM during April-October. See, D.10-06-034, at p. 44.

Q.B.12. What concerns do you have relative to DR resources and RA?

A.B.12. First, none of the rules, whether for flexible, generic system or local RA, are finalized. They are all in some state of flux. Since the definition of RA is the primary driver behind the value of DR and driving the desire for DR to participate in the wholesale market, the lack of definition is a problem in terms of being able to conclusively say whether integration into the wholesale market will be successful or not. These definitions must be fully defined and understood by market participants before they can develop a resource or determine the value of the resource.

Second, there is a troubling trend toward comparability of resource requirements meaning that DR has to abide by the same requirements as generation, like a MOO, that increases the administration of the resource from the DRP perspective without evidence that a MOO will provide any greater utility to the CAISO and may not result in any greater utilization of the resource than was experienced under the IOU contracts. Because, ultimately, high prices, or an abnormal peak requirement (whether it be for generic or ramping resources), will determine when DR resources are of the greatest utility to the system, not for providing base-load energy and not for "normal" daily fluctuations in load. If neither high prices or abnormal peaks or ramps occur, no one should be surprised when DR is not dispatched. If the impetus for integrating DR into the wholesale market is to have DR become an economic resource and be included in the CAISO's least-cost, security constrained dispatch, then economics will dictate when best to dispatch the resource and, that may still be infrequently, given the energy price dynamics in the wholesale market at this time.

Lastly, RA credit for DR is determined based upon the LIP, which is a backward looking mechanism that incorporates weather normalization and other factors, to ascribe a specific RA value for DR resources to be used in the upcoming RA Compliance Year. DR payment is based upon individual event performance. Therefore, there is a misalignment between the value ascribed to the resource for RA purposes and the payment for performance. DR payment and performance evaluations should be based upon the resource's performance over the commitment period, including the overall resource availability, not just on a per-event basis.

C. CAISO MARKET INTEGRATION COSTS

Q. C1. Have you had direct experience with the costs of DR integration into CAISO's market?

A. C1. No. At present, none of the Joint DR Parties are market participants in CAISO.

Q. C2. What is the basis of your testimony as it relates to CAISO's market integration costs?

A. C2. I have reviewed the requirements for DR to participate in CAISO's market and compared it to the requirements to participate in other comparable wholesale markets, with which I have direct experience.

Q. C3. Please describe the basis for your comparison of CAISO's requirements with these other markets?

A. C3. While I do not have specific dollar estimates to provide as far as the actual costs to integrate into CAISO's market, I have reviewed CAISO's requirements for participation and have direct experience with respect to the market integration costs of other markets that can be compared to the requirements proposed by CAISO. Specifically, the other "markets" to which I am referring include ERCOT, and PJM. These markets operate to provide the similar services as the CAISO and, therefore, offer a fair comparison for this purpose. Based upon the requirements to participate in CAISO relative to PJM, I expect, on just the internal resources needed to manage the program, that at least 2 times the full-time equivalents (FTE) per MW will be necessary.

Q. C4. Is it your opinion, then, that the categories of costs necessary to integrate DR resources are the same for both the CAISO and these other markets?

A. C4. Yes. The general categories of costs would be the same; but, the requirements and the actual costs to implement participation in CAISO relative to other markets would not be the same.

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Q. C5. Please describe what those same categories of costs that would be necessary in order for DR resources to integrate into CAISO's market.

A. C5. The categories of costs that a Demand Response Provider (DRP) would incur in order to integrate into the CAISO's wholesale market include the following:

(1) Connections to meet CAISO's system/communication/telemetry requirements;

(2) Becoming or retaining a scheduling coordinator;

(3) Data requirements:

- Operational data, required for operational purpose, will need to be available in "near", real time. This could be accomplished on a NOC-to-NOC basis, but the quality of the data will not be examined for accuracy and the value is more directional and indicative of the magnitude of the response. By contrast, PJM has no requirement for near real time operating data. Capacity/reliability and energy/economic resources can be provided by resources with hourly interval meters. Settlement data may be submitted on the basis of utility billing cycles up to 60 days after dispatch. PJM is monitoring load buses and can "see" the cumulative result of demand response activity without the necessity of expensive data collection and monitoring at the provider site or the PJM control center. Ten minute and 30 minute reserves from demand resources require only one minute interval metering and may be reported within 2 business days – no telemetry required. PJM has found that 10 minute reserves from demand resources perform at least as well as generation and have contributed to measureable reductions in costs. Only Frequency/ Regulating resources are required to have telemetry interfaces with PJM. The distributed nature of demand resources means that the response of any particular resource will not have an impact on reliability of the grid, unlike the impact of a large central station. PJM's approach to DR carefully considers the real need for data for actionable operations

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purposes rather than trying to impose the same requirements on all resource types.

- In California, settlement data will be on a resource basis and the quality of the data will be expected to be within a maximum tolerance band. This data will be transferred from the IOUs to the DRPs and must be converted from revenue quality to settlement quality within approximately 10 days. Green Button Data may reduce some of the delays with processing data.
- The current data quality requirements of CAISO are materially more onerous than the other markets. Taking results out to too many decimal places adds significant complexity and rework without a relative added benefit. This is because in addition to meter readings, the settlement amounts are based on baselines, which approximate what the load would have been absent a curtailment. There is little added benefit to hyper precision on meter data if the baseline is inherently inaccurate.

(4) Requirement to bid on a SUB-LAP basis increases portfolio risk by reducing the ability to aggregate because of fewer potential customers in a particular SUB-LAP. Additional complexity is added to customers that are located across SUB-LAPs because of multiple bids and separate settlement payments depending on pricing within in a specific SUB-LAP. If performance can be aggregated to a portfolio level over a larger geographic area, like a DLAP or an LCA, the cost can be controlled and managed based on the value of the delivery.

PJM has the ability to dispatch reliability reserves on a transmission zone basis but can dispatch on a zip code basis if needed. The less granular approach facilitates aggregation of smaller and diverse sites and minimizes performance risk by allowing netting of larger groups of resources. The ability to dispatch with more granularity when needed, as opposed to at all times, allows a more focused reliability dispatch when needed while minimizing barriers to entry and keeping costs down.

(5) Costs to the DRP of participation would include software, hardware, personnel, system design and integration. Each of these cost components will have unique estimates depending on the requirements of the market, the DRAM and related tariffs.

(6) Customer engagement costs are often misunderstood and/or under-estimated. The enrollment process for customers can take 3 to 6 months, including prospecting, site surveys and contracting. Compared to PJM and ERCOT markets, where there is not a requirement for telemetry, California customers will need to purchase telemetry adding to the complexity of the sale. In addition, due to sub-LAP and costs of telemetry, the target market will likely be significantly smaller as Aggregators will have to target larger customers within specific sub-LAPs in order to aggregate load.

(7) Software costs will include the programming and testing of logic to comply with the program design and rules. This cost can be estimated at around 4-6 man months depending on complexity.

(8) Hardware costs will be dependent on the entity that is providing the curtailment and the sophistication of the systems within those facilities. Costs can be estimated to be approximately 10% of the auction settled price with a large variability depending on facility make up. Commercial buildings with multiple tenants will increase costs with more points to connect per kW and larger industrial entities will have fewer points per kW.

(9) Personnel costs are based on the number of transactions required to process for each kW on an on-going basis. The costs related to necessary personnel will usually dictate a minimum portfolio size in order to breakeven, somewhere around 15 to 20 MW depending on market parameters and complexity. This support can be leveraged for resources in excess of 15-20 MW. Third party providers may be able to support this effort with a dedicated staff to support the market requirements. A third party support system could normally cost approximately 10% of the market closing price.

(10) Operations system design and integration would normally be a one-time cost to set up and then be driven by changes/updates to the requirements. This initial set up cost can be estimated to be approximately 6 man months depending greatly upon the program requirements.

(11) Telemetry costs can be a significant component of integration costs and are certainly relevant relative to the metering requirements of other markets. While a strict interpretation of telemetry requirements for DR resources would be uneconomic, CAISO has efforts underway to explore alternatives to telemetry, while still meeting the need to monitor the system conditions and resources in "near" real time. These efforts are ongoing and it is premature to determine if CAISO's solutions will be workable.

In conclusion, the costs associated with establishing any new program are greatly dependent on the specific requirements of the program. Excessive one-time costs to set up and develop resources can be a barrier to entry and a discouragement to participation. In addition, if the resource requires a lot of administration, requires a lot of on-going support or has high participation costs, then the maintenance costs of the program will be higher. On-going support costs will need to be supported by compensatory market prices and minimum resource sizes.

Q. C6. How do these costs compare as between CAISO and other markets.

A. C6. The costs of telemetry and the requirement to deliver on a sub-LAP basis are the main differences between CAISO's wholesale market design and those of other markets. In other markets, such as PJM and ERCOT, telemetry is only required for DR for certain ancillary services. We expect this cost to be a significant barrier to enrollment in the CAISO market. Key costs are in customer acquisition and communications platforms. Customer acquisition costs can increase with more complex requirements and configurations. Customers need to understand the options available n order to make informed decisions – and explaining a lot of options is costly. Sub-LAP bidding and settlement and a MOO adds to complexity and uncertainty regarding the likely amount of dispatch – thus raising a barrier to customer acquisition.

PJM started simply with a single reliability product that was easy to understand and sell. It has evolved into multiple products but the initial simplicity was critical to establishing a robust demand resource presence. It is worth noting that PJM's simplicity incorporates the ability to use existing hourly interval metering without the need to establish expensive customer to aggregator and aggregator to RTO telemetry. This decreases costs substantially. Systems development costs are more difficult to compare because aggregators may offer differing services.

Q. C7. Do you have an opinion on the range of costs that they would consider to be reasonable?

A. C7. An opinion on this issue is reserved until the cost estimates of the IOUs have been provided and reviewed.

Q. C8. For costs outside the range and therefore unreasonable, please provide examples of ways to decrease those costs.

A. C8. Reduction of complexity in settlements, M&V and bidding will reduce cost. Lower penalty structures will also lower overall program cost structure and encourage customer participation. Specific review of each of the measures should be included in the workshops and discussions to ensure the most cost effective approach and that the related value is commensurate with the level of cost being requested. We would suggest that sub-LAP bidding be eliminated and replaced with requirements to deliver and settle on a DLAP basis, unless the resource is needed to perform at the sub LAP level. Such a requirement should be accompanied by revisions to performance requirements or compensation when dispatched. We would urge the CAISO to consider, as PJM does, that the need for telemetry for large central resources is related to the reliability impact of large facilities on the system and not the need to monitor every managed resource in real time. After all, CAISO does not need to "see" each individual load in real time – a collective view is sufficient. Likewise, we would suggest that impact of small distributed resources can also be monitored in real time on a collective or bus basis.

Q. C9. Has a list of solutions for decreasing CAISO market integration costs been proposed by any party to this proceeding with which you agree?

A. C9. Yes. On December 13, 2013, Pacific Gas and Electric Company (PG&E) filed its Response to Joint Assigned Commissioner and Administrative Law Judge Ruling and Scoping Memo. In that Response at pages 12 through 13, PG&E offered a list of potential solutions for decreasing CAISO market integration costs. This list includes steps to improve, simplify, and reduce costs of bidding in DR products, dispatching DR, and providing telemetry or "visibility" to CAISO for demand-side DR. This list represents a good summary of the solutions that need to be considered as a starting point decreasing CAISO market integration costs. In addition, eliminating the need for "telemetry", in the strictest sense of the word, eliminating a requirement to bid and settle on a sub-LAP basis, unless the resource is required on a sub-LAP, allow for settlement across dispatched sub-LAPs, eliminate a MOO and require DR resources to be available to be dispatched by the CAISO under specific operating conditions.

While DR resources that participate in the wholesale market are used to address transmission conditions and supply shortages, these resources can also be used to provide benefits to the distribution grid. Existing DR programs can be used to address local distribution system needs as well as transmission system needs. There are ways to make the resource available for both. On a day-ahead basis, based upon objective criteria, the IOU and the CAISO can make a determination as to whether DR can better serve the needs of the transmission or the distribution system. If there were times when the availability of a DR resource was not needed for economic or reliability purposes in the wholesale market, especially since DR will likely not clear in the wholesale market in many hours, the DR could be available to the distribution system. CAISO and the California utilities are encouraged to explore whether this approach could increase the value of DR to both the transmission and distributions system operators by directing DR to its highest and best use in addressing the most critical hours of either system. For example, Consolidated Edison (ConEd), in New York City, has several programs that allow the New York Independent System Operator's (NYISO's) capacity resources to be dispatched in local areas where distribution systems are less than robust. The M&V requirements are the same for both ConEd's and NYISO's programs; but, the capacity based compensation is separate.

D. SUPPLY RESOURCES ISSUES

Q. D1. Please describe the list of characteristics the Commission should use in determining how to categorize or differentiate between load modifying resources and supply resources.

A. D1. As described in the Resource Adequacy responses, the Commission previously distinguished between supply-side and load modifying resources based upon whether it was dispatchable by the IOU or not. In this proceeding, the question as to whether or not a resource is a supply-side resource is dependent upon bidding into the CAISO wholesale market subject to a must-offer obligation (MOO). As also previously mentioned, a MOO should not be applied in all hours, but, rather, the DR resources should be required to be available to the CAISO when certain system conditions are met. In fact, of the wholesale markets, only ISO-NE has a MOO and, at least partially as a result, the amount of DR participation has been reduced.

When DR resources bid into the wholesale market, they are prohibited from bidding below the net benefits test (NBT) threshold.[17] There will be many hours in which DR resources will not clear, because the NBT will exceed the LMP. But, further, DR resources will not clear until the market signals indicate there is a need for DR resources, not when energy is plentiful and prices are low.

The expectation should not be that DR resources will clear in the energy market and be dispatched in most hours. That is not the nature of DR to be a provider of energy in most hours. DR bids will exceed the average market clearing price in most hours because it is expensive for customers to interrupt their energy. There must be a need for DR resources evidenced by either system conditions or price. The opportunity costs for customers are not low and vary from customer-to-customer and from day-to-day and hour-to-hour. Not all business and operation days are the same for the consumer. If production is lagging monthly targets, then companies will want to produce to meet those targets. If orders need to be filled by certain dates, then the efforts of the company will go toward filling those

[17] D.12-11-025, Ordering Paragraph 1, at p. 67.

orders. If a homeowner is hosting guests during a particularly hot day, they may not wish to curtail their use of air conditioning. As such, it is the job of the aggregator to manage the ability of its customer resources to perform with the varying availability and capability of the individual customers within a resource.

Bids to provide energy will reflect the willingness and ability of the customer to curtail, which can be difficult to quantify rigorously and requires aggregators to develop reasonable estimates based on prior experience and current conditions. There may not be a lot of DR dispatched based upon the low clearing prices reflected in the CAISO's market analysis. However, by requiring DR to bid into the market at all times of day throughout the year the MOO both reduces the ability of otherwise cost effective DR to participate and may raise questions regarding the reasonableness of a DR resource's bidding strategy.

Use limitations have not been discussed as it relates to DR for purposes of participating in the wholesale market. DR resources often have use limitations including: a maximum number of hours that they can be dispatched; a minimum run-time; varying availability for certain hours of the day; with limitations on the number of calls per day and the number of consecutive days, etc. The main concept is to have the resource available when it is needed, but not to over-use or exhaust the resource when it is not needed.

As part of the MOO, DR resources will be required to bid into the day-ahead and real-time energy markets and will learn, upon the close of those markets, when the DR resource has a dispatch obligation. If the resource is required to meet the generic resource obligation, then it may be required to dispatch between and 1 and 6 PM. In that instance, if the resource participated and was accepted, in the day-ahead market, it will know one day in advance. If the resource participated and was accepted in the real-time market, it will know 75 minutes in advance of the dispatch hour. The requirement to bid into both the day-ahead and real-time markets could mean that the resource obligations could change from day-ahead to real time, with only 75 minutes notice. In addition, a resource could be rejected in the day-ahead, but is accepted in real-time, and have only

75 minutes to dispatch the resource in response to the dispatch instructions provided by the CAISO. This could occur on a regular basis.

It is the case that the companies that comprise the Joint DR Parties are all participants in various wholesale markets, and do, therefore, support, as a general matter, DR participation in wholesale markets where that participation supports, rather than hinders the development of new DR resources. However, it has not been demonstrated that the integration of DR resources into the CAISO market will increase DR penetration. Instead, DR integration may actually threaten the existing DR resources that have been developed. At present, no compelling economic case has been made to attract aggregators or customers to participate in CAISO where there are too many rules still under development and requirements for participation that are more onerous than other markets.

Q. D2. Should DR be required to be dispatched on the same basis or frequency as a peaking plant?

A. D2. While the CAISO may seek to require resources that can meet the dispatch requirements for a natural gas peaker, such an approach leaves valuable preferred resources out of the market, reducing overall market efficiency, driving up emissions unnecessarily, and maintaining CA's dependence on fossil fuels. Other organized markets such as ERCOT and PJM, have recognized the diversity of characteristics among all resources. ERCOT staff has recommended a more flexible economic dispatch methodology that does not require all resource meet a certain dispatch time limitation but rather chooses resources based on cost and ability to meet current system needs. Currently being discussed as "multi-interval Security Constrained Economic Dispatch" it has been recognized by staff and DR providers as a necessity to incorporate DR into ERCOT's energy markets. Further, ERCOT's ERS program recognizes this variability by providing customers with the opportunity to bid in as ERS-10 or ERS-30 Resources, that is, resources that can be dispatched within 10 or 30 minutes respectively to meet system reliability needs. PJM currently operates their real-time markets in a manner that allows for resources with diverse characteristics along these lines.

Q. D3. Please describe how your proposed list of characteristics would apply to demand response programs and whether those programs should be classified as a supply resource.

A.D3. Each of the IOUs' Aggregator Managed Portfolio (AMP) contracts, Capacity Bidding Programs (CBP), Base Interruptible Programs (BIP), and Demand Bidding Programs (DBP) have the primary characteristics necessary to be viewed as a supply resource: that is they can deploy within a predictable timeframe and with a predictable level of accuracy to meet the needs of the system operator or utility. Just because resources possess those characteristics, however, does not mean they should be required to participate in the wholesale market. Existing DR programs are dispatched based upon specified program design features. Integration into the wholesale market suggests that the dispatch criteria will change from the current design to something directed by the CAISO. However, to preserve the value of the resource for both the IOUs and the CAISO, there may be a need to integrate the ways in which the resource can be useful for both distribution and transmission purposes. In addition, it is important not to drive the DR resource requirement to closely mirror those of generation resources. It is important for the CAISO to balance its operational needs with the capabilities of the resources available to it and with overall economic efficiency in mind.

With a more flexible approach to incorporating DR resources, the overall cost of procuring and delivering DR will be lower, as will overall market prices. DR that is aimed at providing non-spinning reserves or Flexible Ramping (an expected service from CAISO) could be used sparingly. Operating reserves and capacity reserve products will be used by CAISO when needed, and not to meet energy market needs. When used, these DR capacity resources are expected to be less costly than generation options and transmission lines to meet those limited needs. At different times, DR can be used for to reduce locational transmission and distribution constraints, particularly if distribution needs are non-coincident with wholesale market needs.

For example, in PJM, generators meet RA performance criteria by maintaining availability during seasonal periods. It is possible, and common, for generators to fail to perform during emergencies and still be considered a viable RA resource, without penalty. DR resources are heavily penalized for failure to perform during an event. There is, therefore, a misalignment of the dispatch and performance expectations as between generators and DR resources: generators have broad dispatch and performance requirements, over an RA compliance year, while DR resources' performance is judged on a per-event basis. Therefore, the Commission should change the basis upon which DR performance, and payment, is judged to coincide with the determination of RA credit for the resource, as described above, in the RA Section.

Q. D4. In summary, what is your position on the proposed Demand Response Auction Mechanism (DRAM) included in Attachment B of the Revised Scoping Memo?

A. D4. With respect to the Commission's Workshop held to discuss the DRAM on April 28, 2014, it was helpful to better understand the intended operation of the DRAM. However, I have serious concerns with many aspects of the proposal, including its efficacy.

An understanding of the DRAM proposal has been improved by the informal CPUC workshop on April 28, 2014. Overall, the DRAM proposal intends to fix the *missing money* problem for DR resources by providing a capacity payment. DR resources, which participate in the DRAM, will be used to meet various RA requirements, flexible, local, and system RA. The utility will have discretion to choose what it needs, among these resource types. It is unclear how the utility will make known how much of the respective types of RA capacity it needs. In this regard, the "auction" mechanism is largely non-transparent. Further, resources will not "clear" at a uniform price that represents a market clearing price for the resource, thereby sending a clear signal to all as to the value of capacity at any point in time. The opaque nature of this proposal is amplified when the resource requirements relative to its participation in the wholesale market are, as of yet, unknown.

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Distribution-level DR can provide value to grid operators by responding to contingencies, voltage changes, and the like, which suggests that DR can be highly valuable if it is optimized for both purposes.

Given that the DRAM is a pay-as-bid mechanism, with a cap, and not a true auction mechanism, which produces a single clearing price for all comparable resources. That, in combination with the low energy price signals in CAISO, it is unclear how, in combination, these processes will indicate that the DR resource's participation in the wholesale market is valued. The only public information will be an average of submitted bids which tells nothing about the value of the resources acquired. Whatever the amount paid to a DR resource, it must be compensatory for purposes of implementing systems, enrolling customers, and providing customer with an appropriate and attractive incentive to participate. With economies of scope, such as use of DR for both wholesale and distribution needs, the value is increased which can both lower overall costs and allow targeted DR to be more effective.

Q. D5. What are those concerns?

A. D5. Those concerns include the following:

- A lack of differentiation among the products that will be offered. If I understood the proposal correctly, there would be two auctions: one for emergency resources and one for all other resources, which would include flexible, local and generic capacity. It is unclear how one auction for flexible, local and generic capacity would provide a meaningful price signal for DR capacity, as each of these resources have different characteristics and obligations.

- While the proposal suggests a declining *as-bid* auction, it layers on top of that proposal, a price-cap that will be administratively determined based on an average cost methodology. While it is hoped that declining, *as-bid* auctions will identify the lowest cost resource to meet the specified need, this auction will add an administrative element to further restrict bid consideration by layering on top of the bids, an administratively set price-cap. The price cap could eliminate resources that have a higher value to the system in favor of resources that have a lower value to the system.

- The DRAM Proposal suggests that certain contract provisions will be standardized. Yet, there are many provisions that will not be standardized and those elements, which define the resource obligations, will have a significant effect upon DR resource value.
  - It is usually not feasible for a DRP to provide the list of customers that will participate as a resource at the time a bid is submitted. The DRP takes on the performance risk for any obligations to which it commits. But, this is difficult for other reasons as well. DR Resource registrations will not be static for any period of time during which the DRP has an obligation, however. Customers decide to come and go at their will. The CAISO registration process does not easily accommodate changes in registrations.
- For the foregoing reason, a DRP should be able to trade into or out of the position it has accepted as part of an auction mechanism. A restriction on trading increases the risk associated with participating in the auction and is unreasonably rigid.
- The auction is primarily designed to address DR capacity payments in exchange for accepting RA requirements; however, RA requirements have not been finalized. They are being developed as we speak. CAISO must receive approval from FERC for its FRACMOO Proposal. CAISO is in the process of developing generic RA requirements for DR resources in its RSI Proposal and local RA is not finalized either. It is difficult to create an auction without the products being fully developed and accepted by the Commission and FERC.
- Seasons versus annual auctions. It probably makes sense to have an annual obligation and seasonal obligations. However, the seasons may be broken into other periods. For example, for flexible RA, November-March may be a

good grouping. For generic resources, perhaps May & June, July & August and September & October.

- Average capacity cap may discourage participation and result in the selection of lower value resources. An auction will reveal a public price for a standardized product that is available to all providers of the standardized product. Selected bids won't know what they will be paid until the end in a non-public process, when the cap is revealed.
- As was discussed at the DRAM Workshop on April 28, 2014, the DRAM Proposal should be clarified that, to the extent the Commission adopts a must-offer obligation for DR resources to participate in the wholesale market in exchange for a capacity payment, the resource should be able to satisfy this requirement by bidding to supply any of the services that clear in CAISO market, including energy, ancillary services or any flexible ramping product, and, thereby, satisfying the requirement to bid the resources into the wholesale market. However, as a general principal, and as articulated throughout this testimony, a MOO does not make sense for DR resources. Instead, a trigger based upon system conditions or economics for where and when the resource is needed either for transmission or distribution purposes, is a better option.

Q. D6.Can you provide examples for a capacity procurement mechanism that has been adopted in another market?

A. D6. ERCOT's Emergency Response Service (ERS) provides a helpful primer on successful and unsuccessful components of DR auction bidding mechanisms. As with the DRAM, ERS was developed to ensure resource adequacy in ERCOT through the voluntary participation of end-use DR customers/providers who bid into an auction for the opportunity to curtail usage during emergencies. While the program initially struggled, today it provides over 600 MW of diverse DR resources through a unique bid auction using a clearing price mechanism to select the most cost-effective DR providers. The results of the auctions are quickly made public, in contrast the proposed DRAM auction in which prices are kept confidential. The ERS program initially used a pricing mechanism similar to that proposed by the CPUC Staff, in which the system operator selected bids based on a confidential internal process and paid DR Resources as bid, keeping most information confidential.

The changes to ERS, in terms of the clearing price mechanism, are relatively new, but the capacity procured during ERCOT's first use of the single clearing price auction represents the highest amount of DR capacity in ERS to date, at a low $/MW price relative to recent auctions using the pay-as-bid methodology. Both ERCOT and DR providers expect that this new clearing price mechanism will create a more robust bidding process and increase DR supply through increased transparency and a clearing price approach that is well founded in economic theory.

At one time, ERCOT was using a "pay as bid" mechanism, which led to participants guessing at the price and submitting bids accordingly. They've since shifted to a clearing price auction where the cleared amount appears to be based on available dollars, though ERCOT has some flexibility to allocate the funds to different hourly and seasonal commitment periods. The Public Utility Commission of Texas (PUCT) limits the annual funding of the program.

The PJM auction process allows for a competitive landscape to ensure the highest amount of qualified resources can be bid into the market. Multiple auctions (3-years forward and true-up auctions) for the same delivery period allow for flexibility and refining of load requirements and delivery mechanisms as facts and circumstances change over time. The clearing price mechanism for PJM allows for the closest alignment between the grid demand and the availability of the supply resources. Tariff definitions are detailed enough to eliminate the need for separate contracting activities beyond the auction clearing.

Q. D7. Are the proposed contract durations proposed in the DRAM sufficient or appropriate?

A. D7. It is fine to have varying durations. There should also be an option for longer-term contracts. The contract period should be of long enough in duration to ensure continuity of the resource but also allow flexibility to support economic changes in the market. Shorter-term contracts can increase the cost to participate and be counter-productive to the goals of the program. An auction structure, similar to PJM, whereby bidding occurs 3 years ahead of the delivery period effectively amounts to a 3 year contract with the ability to negotiate as the delivery period approaches, to ensure new facts are taken into consideration.

Short-term auctions provide substantial uncertainty about outcomes in later rounds, and limit the amount of investment that can be put at risk to provide DR programs to customers. As a result, short-term "one shot" auctions may produce higher priced results; although the use of *as-bid* auctions may be an attempt to reduce the average profits of the winning bidders, economic theory suggests this approach will raise the overall cost of the program to ratepayers.[18]

Q. D8. In addition to the elements listed in this DRAM proposal, are there provisions that should be included in a standard contract?

A. D8. While the DRAM proposal, and the informal workshop discussions, suggests that CAISO RA requirements, including FRACMOO, will be imposed regarding DR availability, duration, and ramping, the following DR operating characteristics and related contract terms must be considered in determining the product. Many of the items listed in the following are self-explanatory, but are clarified where appropriate:

- Operating characteristics of the resource, such as:
  - Hours of availability (hours of the day the resource will be available, total hours for period (annual or seasonal)
  - Hours of dispatch (total hours for period (annual or seasonal)
  - Non-holiday weekdays, all days
  - Number of hours resource is required to be dispatched per event
  - Number of events/day/period
  - Notification period and dispatch requirement to ensure the resource is able to respond.

[18] "Single Clearing Price in Electricity Markets," Ross Baldick, February, 2009: http://www.cramton.umd.edu/papers2005-2009/baldick-single-price-auction.pdf. See Appendix B hereto.

- Best efforts for periods outside of specified windows to allow flexibility and increased participation
- Any performance assurance constraints and remedies
- Service-level agreement requirements for CAISO and auction desk, operation and settlement timing, in order to build proper support network
- Indemnification requirements
- Assignment and transfer rules and options to ensure understanding and transparency
- Bid requirements
- Measurement and verification of delivered capacity
- Liability limitations
- Default rules and remedies
- Confidentiality governing laws

Q. D9. Please indentify any benefits or, conversely, drawbacks to holding one auction per year for seasonal products (May-Oct; Nov-Apr)?

A. D9. There are benefits and drawbacks to having only one auction per year for seasonal products. In terms of benefits, it is administratively easier and reduces the level of regulatory engagement. It reduces uncertainty for end-use customers, by providing a longer planning horizon for which the terms of providing their services are known. As has been demonstrated in other markets, as the number of auction periods increase, so does the complexity and uncertainty of the auction, making it difficult to engage new customers in DR programs. However, more frequent auctions that are occurring closer in time to the delivery period result in more certainty of the bid.

Breaking the auction period into seasons seems to serve two purposes in this instance: first, by creating shorter periods it provides some flexibility to customers and the CAISO to adapt more quickly to changing market and environmental conditions; second it helps to target DR resources to the season during which they are best able to provide value to the CAISO. For some seasonal loads a two-season auction approach may work, however as the “seasons” proposed encompass 6 months, the weather characteristics change significantly over the duration of each period. This will make it very difficult for resources that are seasonally variable, particularly residential loads, to participate in the auction. A four-season program may better serve the CA market as there is a great degree of difference in the needs of the grid between spring months and summer months as well as that relative need vs. the winter months and fall months.

DR resources that can provide capacity for RA may be very different during the milder shoulder months than those during the more extreme winter and summer months, and in order to procure DR for RA purposes as efficiently as possible these differences should be taken into account within auction seasons. For this reason we recommend the CPUC consider 3-4 annual contract periods: winter, summer and shoulder (this last period could be non-consecutive).

Of critical importance to the procurement of new DR is the time period between the auction and the delivery period to allow for adequate testing and other necessary procedures when bringing a new resource to the market. To that end, the following characteristics should be part of the auction:

- For the initial auction, there should be at least a year prior to the delivery period to allow for the DRP and the CAISO to develop their systems and implement the auctions and the resulting obligations on the resource. The auctions should occur at a period that provides enough notice to respond and activate resources as well as close enough to the delivery period to provide a quality line of sight on ability to deliver.
- Auctions that are conducted a number of years, 3, in advance of the delivery year must provide an opportunity for parties to adjust their position going into the delivery period. A true-up auction or the allowance of trades or sales of positions should be included.
- Auction details should be consistent with the directional needs of the state and market.

Q.D10. Do you have an opinion on the merits of the schedule adopted for the proposed DRAM auction?

A.D10. There remain several parameters that require negotiation in the contract as discussed above. 60 days for bid selection and contract signing may result in the time for negotiation being compressed.

Q.D11. Are there additional considerations, other than basing the capacity cost cap for each auction on the average of bids received (per auction), that should be considered in constructing a capacity cost cap?

A.D11. A capacity cost cap should not be included for the reasons stated above. The cap will ensure that the only resources that are selected are those with a lower price, but those resources may also be providing a lower value to the system. In addition, an auction should provide a clearing price, that is made public and that is the same for all comparable resources.

Q.D12. Do you have any recommendations on the DRAM's inclusion of emergency demand response resources, which, in turn, would mean that these resources must receive their capacity payments via a competitive mechanism?

A.D12. The DRAM Proposal suggests that a separate auction will be held for emergency DR resources. All other forms of DR, system, local or flexible DR capacity, will be solicited through a single auction. It is not clear as to why emergency resources are being auctioned separately from the other DR resources. It is also not clear as to why all other forms of DR capacity will be auctioned together. It seems as though the auction should be directed toward the specific type of resources that is sought. Each of these "forms" of DR have, or will have, specific uses to the system and specific performance descriptions and requirements. Therefore, emergency, flexible, local and system RA should all be independently auctioned.

Q.D13. Do you believe that competitive, or other concerns, arise from the proposal in the DRAM for the Commission to have the option of publishing a weighted average of bids received at some point following each auction?

A.D13. It would be preferable to release the value of the resources procured, not just solicited. To release a weighted average of bids received says nothing about what was actually selected. PJM, MISO and ERCOT release the clearing prices, by region, for the capacity that was procured in the auction. It indicates where capacity was valued more highly than in other regions. The release of the data creates a historical record from which to compare to previous auction results. As stated previously, a better construct would be to pay all comparable providers of capacity comparably, so that there is one auction clearing price for the resources procured for a specific delivery period (seasonal or annual or other) that is published at the close of the auction.

Q.D14. Please provide your opinion on DRAM proposal to apply penalties if deliveries of the DR resource fall below 60% of contracted capacity.

A.D14. There needs to be alignment between the way a DR resource is paid and the way it is counted for resource adequacy purposes. In addition, there should be alignment with the way other RA resources are counted and compensated. Supply-side resources that participate in the wholesale market should be treated comparably for purposes of payment, penalties and RA resource requirements as other resources.

For example, RA capacity is determined through the Load Impact Protocols (LIP) for DR resources. The LIP determines the RA capacity that a utility may count for RA purposes by looking backwards at the performance of the resources over the previous year, including adjustments for weather normalization, and calculates an RA capacity value, by program, that the utility can use to count toward its RA requirement for the upcoming year.

DR resources are paid based upon the performance in individual dispatch events. If a resource performs at 100% on one day, it is paid 100%. If a resource performs at 89% in the next event, it is paid, at least in SCE's service territory, for 50% of the delivered MW, or 44.5 MW for a 100 MW commitment. In other words, the capacity value of the resource is significantly reduced on a per-event basis. The resource is not paid based upon how well, or poorly, it performed over a commitment period (a year or season).

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The current method of paying DR resources on a per event basis and severely discounting the "delivered" capacity, as opposed to penalizing the shortfall, is significantly out-of-step with the way other RA resources are measured and compensated.

For example, if a generating resource commits to provide 100 MW of capacity, and, on any given day, the resource fails to provide 100 MW and instead provides 89 MW, the resource is not penalized by de-rating its capacity payment for that day. Rather, the generating resource may be charged for imbalance energy. The generator's capacity is not reduced to the 89 MW level until it can demonstrate that it can perform at 100 MW the next time. Rather, the generator is paid for the 100 MW throughout the RA delivery year, charged for imbalance energy. It is not until the committed capacity is unavailable more than 25% of the time that the resource will not count toward the RA requirement. In future years, the resource's net qualifying capacity could be adjusted, downward, based on historical performance or future tests. In other words, the generators capacity payment for an RA year is not adjusted based upon the performance of any given day and certainly not to the same extent that DR resources' capacity payments are adjusted. Therefore, while the payment/penalty structured contained within the DRAM proposal is an improvement over previous payment/penalty schemes employed by PG&E and the current SCE methodology. However, it is still quite punitive relative to other market mechanisms and the treatment of other resources.

As such, DR resource performance should be measured over the term of the delivery period for which it is committed, rather than on a per-event basis. In addition, penalties for a shortfall in deliveries should be either assessed against the under-delivered capacity, not the delivered capacity, or reflect imbalance energy charges, similar to the charges that other resources incur in the wholesale market.

Q.D15. Do you have an opinion on the fact that this proposal currently envisions Commission-regulated utilities procuring DRAM capacity on behalf of their own load, but does not include a similar procurement obligation for other Load Sharing Entities?

A.D15. At this time, I do not have an opinion on that distinction, but reserve the right to respond further on this issue in reply testimony.

Q.D16. How should an annual goal for overall DR integrated into the CAISO markets, including the need to identify and define applicable terms, be determined?

A.D16. The issue of Demand Response Goals is addressed in Section II.A. of this testimony. Specific goals for DR integration, however, may be premature at this time. DR integration is, at this time, an experimental process. There are a lot of moving parts. In order for DR integration to work, the Commission and the CAISO are going to have to resolve many outstanding issues in a relatively short period of time. Definition of the resource requirements for DR resources to qualify for RA, the development and implementation of an auction mechanism, and the identification and resolution of several "barriers" to DR participation in the wholesale market, as discussed earlier in this testimony, will all be need to be resolved first. Initial integration experience will also inform the Commission, the CAISO and the parties as to what is working and what is not working. That information will necessitate further processes and the implementation of refinements. The goal should be to learn from the experience of integrating DR resources into the wholesale market. In short, setting goals at this point may create unrealistic expectations.

Q.D17. Do you have an opinion on whether and what methods could be used to improve forecasting with regard to supply resources that will be integrated into the CAISO energy markets?

A.D17. Not at this time.

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Q.D18. Do you have an opinion on the role of a "utility-centric" model and the ability of third party providers to supply resource demand response to meet current and future needs?

A.D18. Yes. DR exists, at all, due to the guidance of the Commission and due to the efforts of the utilities to develop DR resources and to work with aggregators to develop third-party DR resources. The relationship between the utilities and the aggregators will continue for several reasons:

(1) The policy direction to continue to develop DR will continue;

(2) Aggregators bring their expertise to the table;

(3) Aggregators have developed good working relationships with many CA businesses and utilities at this point;

(4) DR contributions to addressing system challenges will grow and expand over time;

(5) Utilities are the largest and most likely buyers of the DR RA capacity value and are the most likely source of capacity payments for third-party DR suppliers;

(6) It is unlikely that the state will move to a centralized capacity market structure.

For these reasons, the success of third party DR programs is dependent upon continued utility support. However, it is likely that the way in which DR programs are administered and the types of programs that are offered will change over time. For example, it may not be necessary to have multiple "flavors" of similar DR programs to participate as supply-side resources. Rather than have a CBP, AMP, and DBP program, future programs are likely to be designed to provide RA and to meet specific requirements of the system. The resource definition will reflect the operating characteristics the resource will have to meet in the wholesale market. Therefore, it would probably be less important that the utility offer its own "programs" so as much as procure resources for the purpose of meeting specific resources needs, like local, system or flexible RA.

Q.D19. Should the IOUs continue to offer rate regulated supply resource demand response if these services are provided through competitive markets?

A.D19. As described above, the role of IOUs may change to be more of a procurer of resources than the provider of "programs". However, for load modifying resources that are not dispatchable, and are, therefore, tariffed services, the utility will remain the sole provider of services.

Q.D20. Should the Commission focus on identifying more of these programs as supply resources and limit the IOUs' role to overseeing the competitive procurement?

A.D20. Yes. It would be a conflict of interest for a utility to bid its own resources into an auction that it administers and where the utility would be the only "participant" to review the bids of others and choose winners and losers.

Q.D21. For supply resources integrated into energy markets without a capacity contract, does the Commission have any role in tracking the resources' load impacts?

A.D21. It is unclear what supply resources would be integrated into the energy markets without a capacity contract and what relationship that resource has for resource adequacy purposes. Under those circumstances, it is difficult to answer whether there should be a role for the Commission in assessing load impacts.

E. LOAD MODIFYING RESOURCES ISSUES

Q. E1. Do you have a recommendation on the list of characteristics that the Commission should use in determining how to categorize a Load Modifying Resource?

A. E1. As stated earlier, DR resources that are dispatchable, but not bid into the wholesale market, are considered to be load modifying resources. The distinction is not the characteristics of the resource, which may be similar or identical to supply-side resources, with the exception that they are, or are not, bid into the wholesale market. Therefore, there are two characteristics of load modifying resources. They are either tariffs with rates, to which customers can choose to respond to the market signals, or they are dispatchable resources, based upon system conditions, that are not bid into the wholesale market.

Q. E2. Using that proposed list of characteristics, do you have an opinion regarding what program(s) should be classified as a supply resource, as defined by D.14-03-026, and whether subsets of customers in existing programs could be sub-aggregated and classified as Load Modifying Resources?

A. E2. Please see the response to D.3. and E.1.

Q. E3. Do you have an opinion on how the Commission can improve current programs designated as load modifying resources in order to meet forecasted needs or if the Commission needs to improve forecasting for Load Modifying Resources and, if so, how?

A. E3. Not at this time. However, I reserve the opportunity to respond to other parties' opening testimony.

Q. E4. If the Commission follows through on its intention to set annual goals for load impacts, do you have a recommendation on how those goals should be determined for Load Modifying Resources and if the Commission has guidelines in placed today that could be used as a starting point?

A. E4. Not at this time. However, I reserve the opportunity to respond to other parties' opening testimony.

Q. E5. Do you have an opinion regarding the ongoing role of the IOUs and third party providers in administering and providing load modifying resources?

A. E5. Yes. I believe the IOUs will continue to administer load-modifying resources.

F. PROGRAM BUDGET APPLICATION PROCESS

Q. F1. Should the Commission consider longer budget cycles for DR Programs?

A. F1. Yes. The utilities should have the opportunity to procure DR resources that conform with the resource definitions for up to 5 years or longer, especially if the resource is procured to meet a long term planning need. DR resource procurement should not be limited to short-term procurement cycles when other resources can be procured through long-term cycles. DR should be integrated in long-term procurement decisions, such as has been done with SCE and SDG&E in D.14-02-033.

Q. F2. If the Commission approves longer budget cycles, i.e. 5 or 10 years, should there be regular reviews of the budgets in between the application approval?

A. F2. No. This is just an additional layer of regulatory intervention that is unnecessary.

Q. F3. How can evaluation, measurement, and verification (EM&V) processes be leveraged to improve demand response programs in longer budget cycles?

A. F3. I have no opinion to offer on this issue at this time; but reserve the right to provide an opinion in rebuttal testimony.

III.
PHASE TWO REMAINING ISSUES

A. BACK-UP GENERATORS

Q. A1. Do you have an opinion as to the status of the IOUs' compliance with the Commission's current policy that does not count demand reduction from demand response programs that use fossil-fueled emergency back-up generation (BUG) towards resource adequacy (RA) obligations?

A. A1. Yes. The Joint DR Parties' positions on issues related to Back-Up Generators are stated in the Joint DR Parties' Joint Response on Phase 2 Foundational Questions and Joint Reply to Responses to Phase 2 Foundational Questions filed in this proceeding (R.13-09-011 (DR)) on December 13, 2013, and December 31, 2013, respectively. As stated in the Joint DR Parties' Joint Response filed on December 13, 2013, this question is only a partial statement of the policy, which has not been implemented.[19]

Q. A2. Do you have a recommendation on how the IOUs should collect data on the customer's use of, or the amount of DR provided by, fossil-fuel emergency BUG during the demand response events?

A. A2. Not at this time.

Q. A3. Do you have a recommendation on methods the Commission should use to exclude demand reduction provided through the use of BUG?

A. A3. Not at this time.

Q. A4. Should the Commission require on-site sub-metering and/or self-certification for BUG during demand response events and how should costs be recovered if on-site metering is used?

A. Q4. The Joint DR Parties do not have a position to offer on this issue at this time.

[19] Joint DR Parties' Responses on Phase 2 Foundational Questions (December 13, 2013), at pp. 10-17; Joint DR Parties Reply to Responses on Phase 2 Foundational Questions (December 31, 2013), at pp. 6-10.

B. <u>COST RECOVERY</u>

Q. B1. Are you familiar with the IOUs' current demand response program cost recovery?

A. B1. Not at this time.

Q. B2. In those circumstances, do you currently have an opinion on whether the current cost recovery policy should be changed or whether there are fairness issues related to cost recovery between IOUs and other LSEs?

A. B2. Not at this time.

IV.
CONCLUSION

The purpose of this testimony (Exhibit JDRP-1) is to provide the Commission with the perspective of DRPs who participate both in California as well as other markets in the United States and globally relative to the design being contemplated for integrating DR resources into the CAISO. While, as a general principle, the Joint DR Parties support participation in well-structured wholesale markets, there are a number of factors, as to the structure contemplated in California, that raise serious doubts that the structure will be successful. Therefore, the Commission should proceed slowly and carefully in analyzing how best to proceed. More importantly, the Joint DR Parties urge consideration of the issues, concerns, and recommendations made in Exhibit JDRP-1, as summarized in Section I., before going any further down the path of integrating DR resources into the wholesale market.

R.13-09-011 (DR)
PHASE TWO AND PHASE THREE
OPENING PREPARED TESTIMONY OF
JOINT DR PARTIES

APPENDIX A

Reference Pages for Footnotes 12, 13 & 14

Footnote 12:
California Independent System Operator (CAISO)
Monthly Demand Response
Net Benefits Test Results
May 2014

Pages 1 through 3

Footnote2 13 & 14:
CAISO Q4 2013 Report on Market Issues and Performance
February 10, 2014

Cover Page and Pages 12 and 15

California ISO
Shaping a Renewed Future

Monthly Demand Response Net Benefits Test Results May 2014

Demand Response Net Benefits Test Results

0. SUMMARY

On December 15, 2011 the Federal Energy Regulatory Commission found the California ISO's proposed net benefits test in compliance with the direction provided in Order No. 745. Accordingly, the ISO is posting the price thresholds and supply curves that would have been in effect for the previous 12 months, as well as the threshold price and supply curve for the next trade month by the 15th day of the current month.

1. BACKGROUND

On December 15, 2011 the Federal Energy Regulatory Commission found the California ISO's proposed net benefits test in compliance with the direction provided in Order No. 745. Accordingly, the ISO has posted the net benefits test methodology with the price thresholds and supply curves that would have been in effect for the previous 12 months[1]. In this report, the ISO is posting the threshold price and supply curve for the month of May 2014, in compliance with the order issued in FERC Docket No. ER11-4100-000.

The Commission also directed the ISO to post the net-benefits methodology and supporting documentation. This directive requires the ISO to include in its tariff within 90 days the net benefits methodology and supporting documentation. Accordingly, the ISO will post the net benefits methodology and any supporting documentation as part of its compliance filing.

2. NET BENEFITS TEST RESULTS

Year	Month	Peak Type	Threshold Price	Price Window
2014	05	ON PEAK	$65.35	[50,90]
2014	05	OFF PEAK	$67.86	[50,90]

TABLE 1: NET BENEFITS TEST THRESHOLD PRICES

[1] The net benefits test methodology and previous 12 months results are documented in the final proposal.

http://www.caiso.com/informed/Pages/StakeholderProcesses/DemandResponseNetBenefitsTest.aspx

Year	Month	PG&E Citygate	Southern California Citygate	Average Gas Price	Gas Scalar
2013	05	$4.07	$4.08	$4.08	
2014	05	$5.00	$4.73	$4.87	1.19

TABLE 2: GAS PRICES AND GAS SCALARS

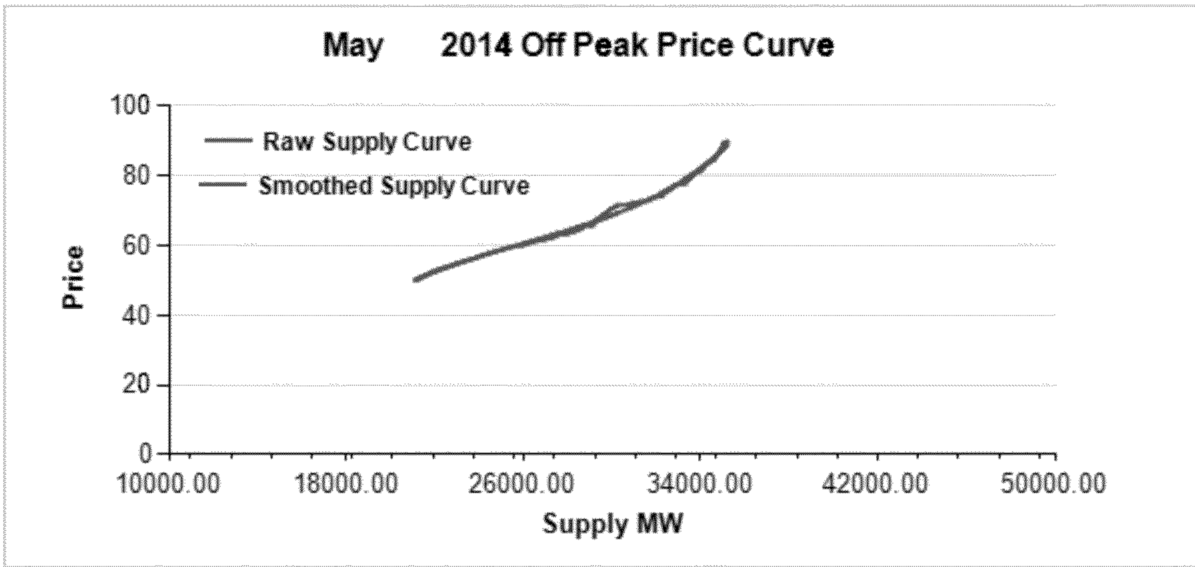


FIGURE 1: May 2014 OFF-PEAK REGRESSION RESULT

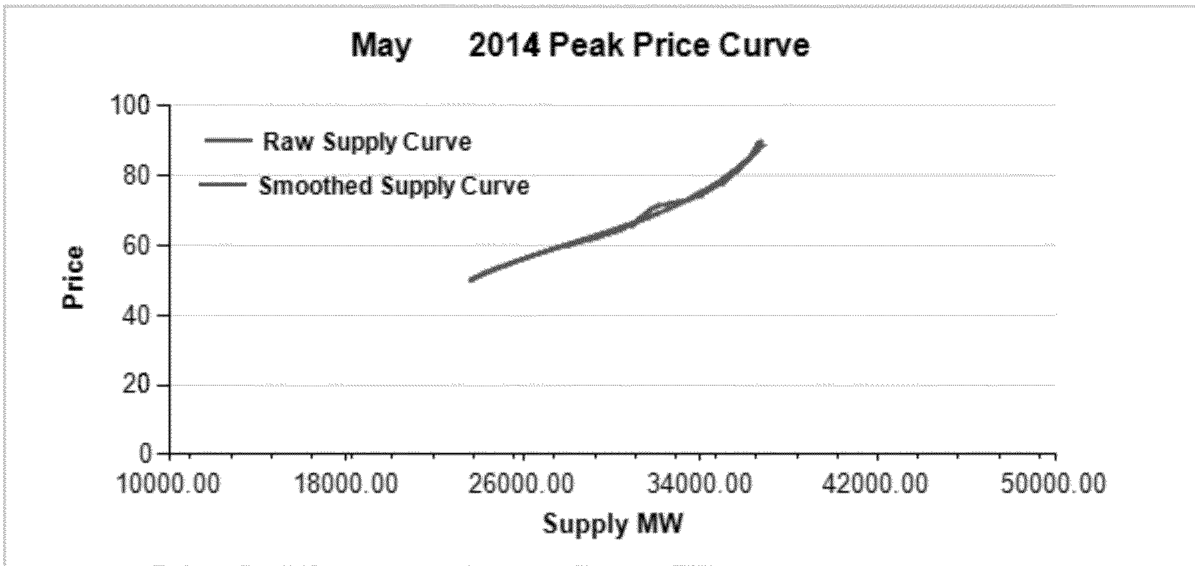


FIGURE 2: May 2014 ON-PEAK REGRESSION RESULT

California Independent System Operator Corporation

California ISO

Q4 2013 Report on Market Issues and Performance

February 10, 2014

Prepared by: Department of Market Monitoring

Figure 1.3 Average monthly on-peak prices – system marginal energy price

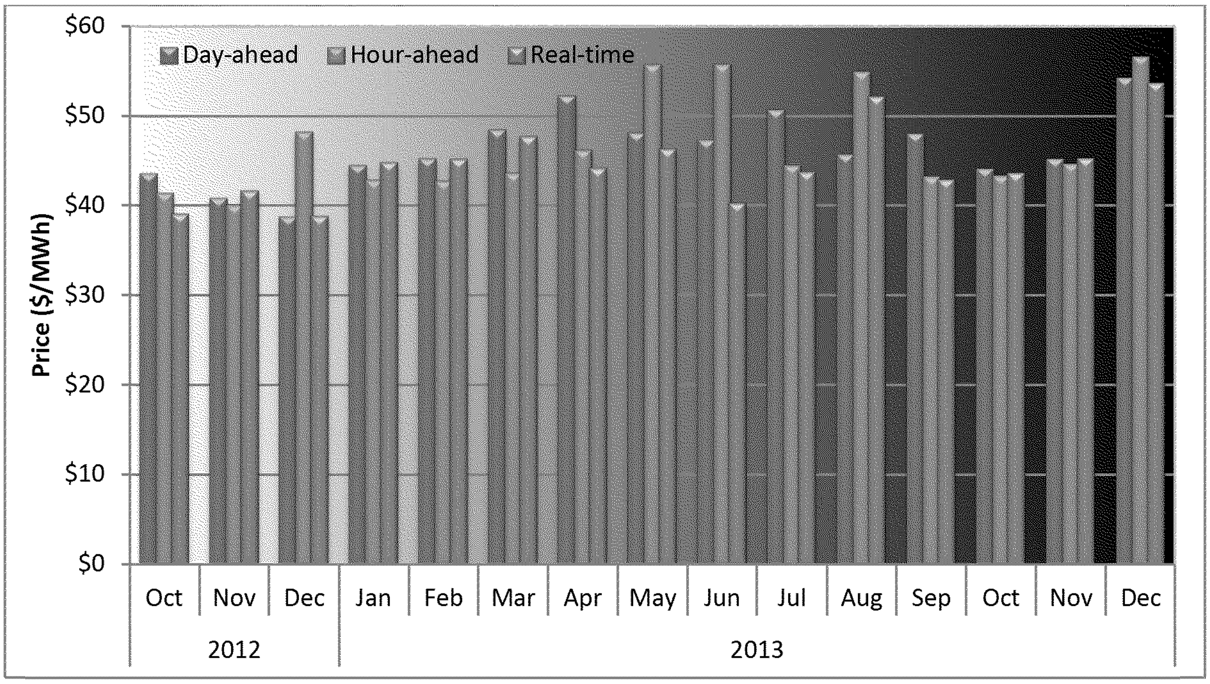
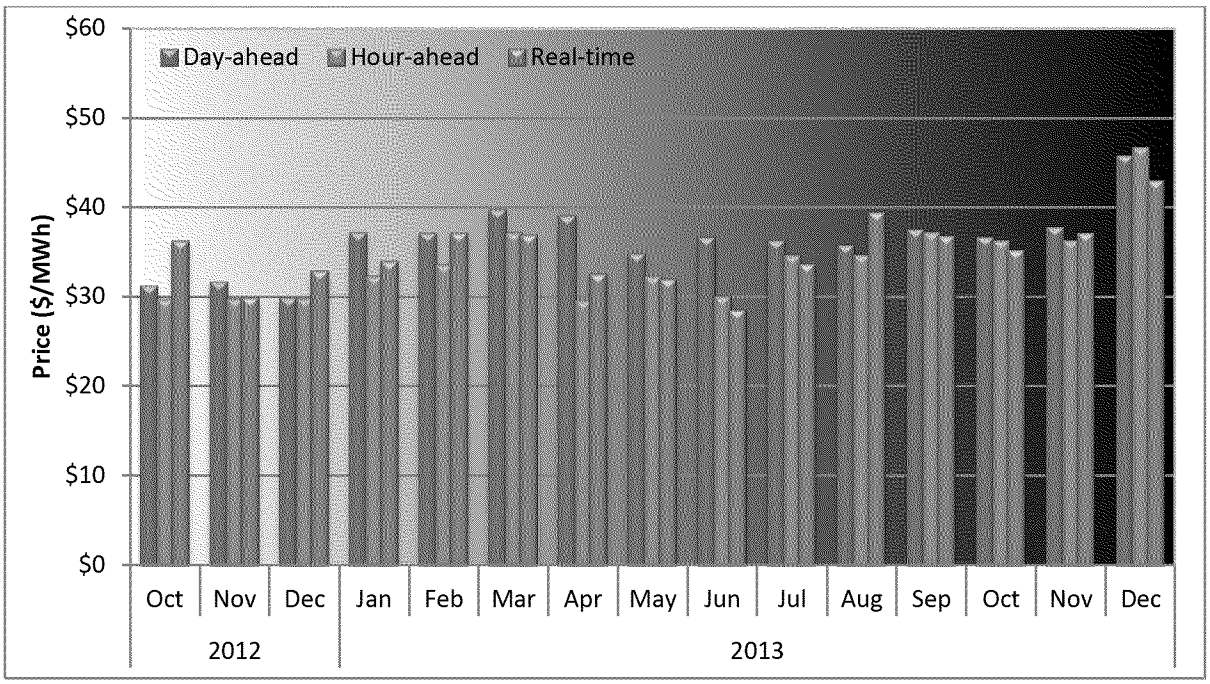


Figure 1.4 Average monthly off-peak prices – system marginal energy price

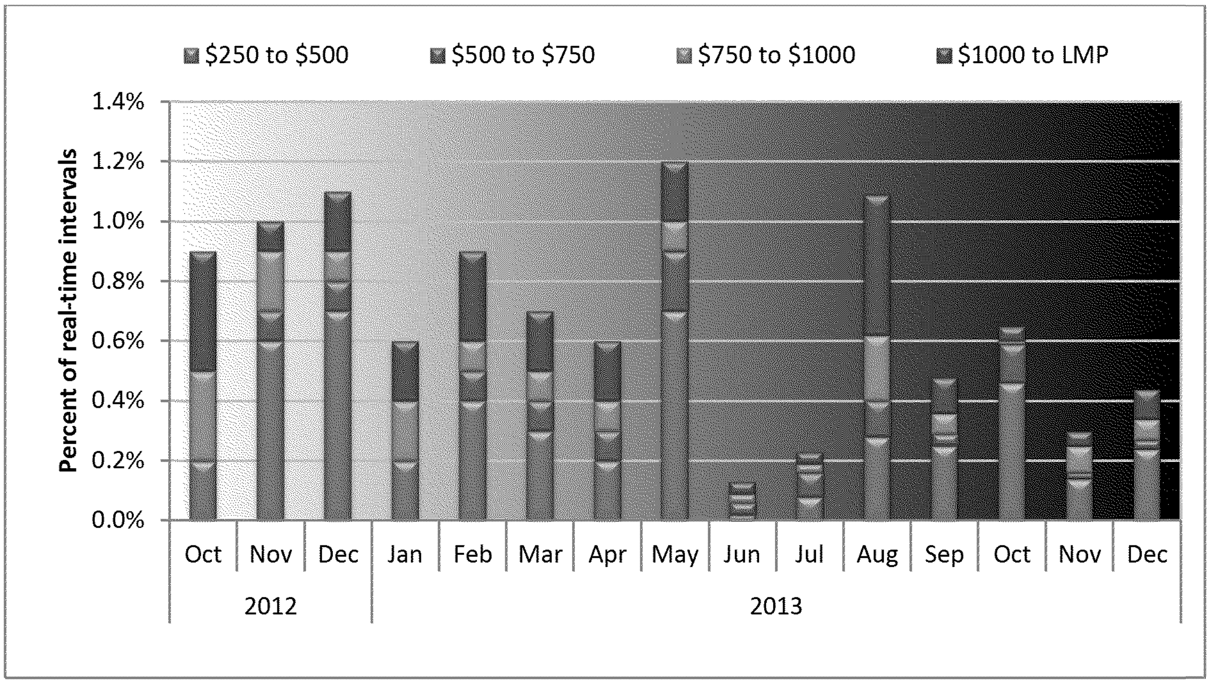


1.3 Real-time price variability

Historically, real-time market prices have been highly variable. This section highlights real-time market prices and provides explanations of real-time price variation.

Figure 1.7 shows the frequency of price spikes that occur in the real-time market. In the fourth quarter, the frequency was about 0.5 percent, slightly below the value in the third quarter and continuing a downward trend in real-time price spikes. As in the previous three quarters, the ISO continued to increase the flexible ramping constraint requirements during the evening ramping hours. This has contributed to the decline in the frequency of real-time price spikes.

Figure 1.7 Frequency of price spikes (all LAP areas)



Power balance constraint relaxation at the interval level can significantly affect average real-time market prices over longer periods of time, such as a month. This is particularly true when positive power balance constraint relaxation events occur, often resulting in system prices at $1,000/MWh. Furthermore, average prices are also affected by negative power balance constraints, due to over-generation, resulting in prices at -$30/MWh.

The number of power balance constraint relaxation intervals resulting from insufficient upward ramping capacity also continued to decrease in the fourth quarter compared to previous quarters and from the fourth quarter of 2012, as seen in Figure 1.8. Power balance constraint relaxations can also occur in the presence of congestion. In the third and fourth quarters, only 2 percent of the power balance constraint

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APPENDIX B

Reference Pages for Footnote 18

"Single Clearing Price in Electricity Markets"
Professor Ross Baldick
February 18, 2009

Cover Page and Pages ii, 10, 15-18

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R.13-09-011 (DR)
PHASE TWO AND PHASE THREE
OPENING PREPARED TESTIMONY OF
JOINT DR PARTIES

APPENDIX C

STATEMENTS OF QUALIFICATIONS

STATEMENT OF QUALIFICATIONS OF MONA TIERNEY-LLOYD

Q1 *Please state your name and business address.*

A1 My name is Mona Tierney-Lloyd, and my business address is P. O. Box 378, Cayucos, CA 93430.

Q2 *Briefly describe your present employment.*

A2 I am currently employed by EnerNOC, Inc. as a Senior Director of Western Regulatory Affairs. I am charged with representing EnerNOC's interests in support of promoting the use of energy intelligent software that provides commercial, industrial and institutional customers with the ability to manage the way they buy and consume energy, and, in turn, provides resources to utilities and system operators to manage the supply and reliability of the electricity system. I participate in state regulatory proceedings before commissions in the Western and Midwestern United States.

Q3 *Please summarize your professional background.*

A3 I have been employed by EnerNOC since 2008. I was previously employed by Constellation NewEnergy, Inc. as Vice President of Western Government Affairs and in other capacities from 2002 until 2006. Previous to that, I was a Director of Western Government Affairs for Enron Energy Services, Inc. from 1996 until 2001. I was employed by SDG&E as a Senior Pricing Analyst from 1994 until 1996. I held rate, supply and forecasting analytical positions at Elizabethtown Gas Company in New Jersey from 1987 until 1994. I began my professional career working as a production analyst for an oil and natural gas exploration and development company outside of Pittsburgh, Pennsylvania. I have a B. S. Degree in Petroleum and Natural Gas Engineering from Penn State.

Q4 *Have you previously testified on behalf of EnerNOC, Inc., before the California Public Utilities Commission?*

A4 Yes. I testified on behalf of EnerNOC, Inc., in the separate evidentiary hearings held in Track 1 (Local Reliability Track) and Track 4 (San Onofre Nuclear Generating Station (SONGS)) of R.12-03-014, submitting Opening, Reply, and Supplemental Testimony in each of those proceedings. I have also submitted testimony in other proceedings before this Commission and the state regulatory commissions in Arizona, Colorado, New Mexico, Montana and Minnesota.

Q5 *What is the purpose of your testimony?*

A5 The purpose of my testimony is to sponsor Exhibit JDRP-1, the Opening Prepared Testimony of the Joint Demand Response (DR) Parties in Phase 2 (foundational issues) and Phase 3 (future demand response program design) of R.13-09-011 (DR). I am sponsoring or jointly sponsoring Sections I through IV and Appendix A.

Q6 *Does this conclude your statement of qualifications?*

A6 Yes, it does.

STATEMENT OF QUALIFICATIONS OF COLIN MEEHAN

Q1 *Please state your name and business address.*

A1 My name is Colin Meehan, and my business address is 5390 Triangle Pkwy NW #300, Norcross, GA 30092 .

Q2 *Briefly describe your present employment.*

A2 I am currently employed by Comverge, Inc. as a Director of Regulatory and Market Strategy. I am charged with representing Comverge's interests before state regulatory commissions and Independent System Operators in Texas and California. I have been engaged in the stakeholder processes relative to flexible capacity resources. I currently lead ERCOT's stakeholder process to revise ERCOT protocols to allow for more effective participation of DR in ERCOT energy and ancillary services markets, referred to as "Loads in SCED." I have participated in various CPUC proceedings in which demand response issues have been addressed.

Q3 *Please summarize your professional background.*

A3 I have been employed by Comverge since May 2013. I was previously employed by Environmental Defense Fund as their Smart Power Policy Manager. Prior to that, I was a wholesale power settlement analyst and nodal implementation specialist at the Lower Colorado River Authority, a wholesale power generator in Texas. I was also employed by ICF International as a wholesale power analyst where I developed the primary wholesale market analysis used for the development of the Model Rule for the Regional Greenhouse Gas Initiative – a multi-state mandatory carbon dioxide reduction program covering 9 states in the Northeastern U.S. In that role I also developed wholesale electric market analyses for utilities and state-level policy makers to assist in policy development and investment decision-making for a variety of assets including pollution control, electric generation, demand response and energy efficiency. I have a B.A.

Degree in Math and Economics from the University of Rochester and an M.S. Degree in Energy and Earth Resources from the University of Texas at Austin.

Q4 *Have you previously testified on before the California Public Utilities Commission?*

A4 I have not previously testified before this Commission, but have formally filed comments in this proceeding. I have testified before state regulatory Commissions in Texas and Illinois.

Q5 *What is the purpose of your testimony?*

A5 The purpose of my testimony is to sponsor or jointly sponsor the following portions of Exhibit JDRP-1, the Opening Prepared Testimony of the Joint Demand Response (DR) Parties in Phase Two (foundational issues) and Phase Three (future demand response program design) of R.13-09-011 (DR): Section II.B.(Resource Adequacy Concerns), Section II. C (CAISO Market Integration Costs), Section II.D. (Supply Resources Issues), and Appendix B.

Q6 *Does this conclude your statement of qualifications?*

A6 Yes, it does.

STATEMENT OF QUALIFICATIONS OF BRUCE E. CAMPBELL

Q1 *Please state your name and business address.*

A1 My name is Bruce Campbell, and my business address is 901 Campisi Way, Suite 260, Campbell, CA 95008.

Q2 *Briefly describe your present employment.*

A2 I am currently employed by Johnson Controls, Inc. (JCI) as a Director, Regulatory Affairs for the Integrated Demand Response group which also operates as EnergyConnect, Inc. I am charged with representing JCI's interests and those of demand response generally before regulators and RTOs in the United States with particular emphasis on PJM. I have been engaged in the stakeholder processes conducted by PJM as it relates to DR integration into the wholesale market in compliance with FERC Order 719 and 745. I participated in stakeholder processes in PJM for more than 15 years with capacity market design being a key focus.

Q3 *Please summarize your professional background.*

A3 I have been employed by JCI and EnergyConnect, since 2007. I was previously employed by Mirant, a generation owner, from 2000 to 2007 as Director of Regulatory Affairs for PJM. Previous to that, I was employed by Potomac Electric Power Company from 1975 to 2000 in a variety of positions including Generation Station Manager and Market Consultant. I have a double degree with a B. S. Degree in Mechanical Engineering and B.A. in Physics from Bucknell University in Lewisburg, PA.

Q4 *Have you previously testified before the California Public Utilities Commission?*

A4 I have not previously testified before this Commission, but have participated in formal proceedings before the Public Utility Commission of Ohio and the Maryland Public Service Commission and have served as a Technical Conference panelist at the Federal Energy Regulatory Commission.

Q5 *What is the purpose of your testimony?*

A5 The purpose of my testimony is to jointly sponsor the following portions of Exhibit JDRP-1, the Opening Prepared Testimony of the Joint Demand Response (DR) Parties in Phase Two (foundational issues) and Phase Three (future demand response program design) of R.13-09-011 (DR): Section II.C.(CAISO Market Integration Costs) and Section II.D. (Supply Resources Issues).

Q6 *Does this conclude your statement of qualifications?*

A6 Yes, it does.