ATTACHMENTS

1. **Draft Workshop Report on the Public All-Party Discussions on June 9, 10 and 11, 2014**

2. **DACC/AReM Presentation, Cost Allocation of IOUs' Demand Response Programs**
   (*June 9, 2014 CPUC Workshop R.13-09-011*)

3. **PG&E Presentation, Overview of CAISO Integration Costs for PG&E** - (Corey Mayers PG&E's Demand Response Department Customer Energy Solutions)

4. **SCE Presentation, CAISO Market DR Integration Costs** - (Demand Response OIR Workshop David Lowrey/Muir Davis – June 9, 2014)

5. **SDG&E Presentation, SDG&E Electric Rule 32 Implementation Costs** (June 9, 2014)

6. **JDP's Cost of Integration Presentation** (June 9, 2014)

7. **Summary of Demand Response Providers Operating in Other ISOs and Key Market Characteristics**

DRAFT WORKSHOP REPORT ON THE PUBLIC ALL-PARTY DISCUSSIONS ON JUNE 9, 10 AND 11, 2014, REGARDING THE ISSUES IDENTIFIED IN THE ORDER INSTITUTING RULEMAKING R.13-09-011

In accordance with ALJ Hymes' May 30, 2014 ruling to parties in R.13-09-011, the Investor-Owned Utilities ("IOUs"), Pacific Gas and Electric Company ("PG&E), San Diego Gas & Electric Company ("SDG&E"), and Southern California Edison Company ("SCE"), submit a consolidated Workshop Report on the discussions intended to resolve or clarify issues identified in the April 2, 2014 Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo ("ACR"). ALJ Hymes' May 30 ruling directed SCE, SDG&E and PG&E to prepare a draft workshop report and file it by June 19 in this docket, with opening comments due June 23 and reply comments due July 3. In her ruling of June 6, 2014, ALJ Hymes changed the filing date to June 24, with comments due July 1 and reply comments due July 8.

I. INTRODUCTION

The April 2, 2014 ACR revised the rulemaking's schedule and scope for Phases 2 and 3 of R.13-09-011. The ACR combined unresolved Phase 2 issues (that is, cost recovery and back up generation) with Phase 3 issues (future DR program design). In addition, the ACR ordered parties to submit opening testimony on May 6, 2014 and rebuttal testimony on May 20, 2014.[1]

Initially, the April 2, 2014 ACR scheduled evidentiary hearings during the week of June 9, 2014. In response to requests for workshop by parties, ALJ Hymes issued a ruling that revised the evidentiary hearing schedule in order to allow for two days of workshops on June 9 and 10, 2014. After commencing the evidentiary hearings with cross examination of SDG&E witness James Avery, ALJ Hymes adjourned the hearings to start a two day workshop.[2] The purpose of the workshop was to "attempt to develop consensus between opposing sides or develop a better understanding of the opposing sides with respect to issues discussed."[3]

During the workshops, ALJ Hymes and parties exchanged information and concluded that significant progress on issues would warrant a continuation of workshops in lieu of hearings

[1] Per Administrative Law Judge Hymes' May 16, 2014 ruling, parties were granted additional time to serve rebuttal testimony by May 22, 2014.
[2] Entities participating in one or more workshops were the Office of Ratepayer Advocates (ORA), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), the California Large Energy Consumers Association (CLECA), The Utility Reform Network (TURN), EnerNOC, Inc. (EnerNOC), Comverge, Inc. (Comverge), and Johnson Controls, Inc. (JCI) (together "Jt. Parties"), the California Independent System Operator (CAISO), Direct Access Customer Coalition (DACC) and the Alliance for Retail Energy Markets (AReM) (together DACC/AReM), the Environmental Defense Fund (EDF), the Sierra Club (Sierra Club), the Clean Coalition (Clean Coalition), Calpine Corporation (Calpine), Marin Clean Energy (MCE), , Consumer Federation of California (CFC), Shell Energy (Shell), Olivine Inc. (Olivine), EnerNOC, the Commission Energy Division (Energy Division), and California Energy Commission staff (CEC). SCE, SDG&E and PG&E together are referred to as the IOUs in this draft report.
[3] Administrative Law Judge Hymes June 6, 2014 ruling.

through June 12, 2014. As a result, parties made significant progress to clarify issues. Evidentiary hearings were scheduled for July 10-11, 2014 (if needed), but have been reset for August 7 and 11 pursuant to the ALJ's ruling on June 23, 2014. At the end of the workshops, parties agreed to continue discussions that might result in the possible settlement.

This Report is organized as follows:

- Section A: Cost Recovery
- Section B: Back-up Generation
- Section C: CAISO integration costs
- Section D: Bifurcation/Categorization of Load Modifying Resource and Supply Side Resource Demand Response
- Section E: Must Offer Obligations
- Section F: Demand Response Goals
- Section G: Demand Response Auction Mechanism (DRAM) and Cost Effectives Protocols (Part I)
- Section H: Demand Response Auction Mechanism (DRAM) and Cost Effectives Protocols (Part II)
- Section I: Additional Issues/Considerations
- Appendix A: Workshop Presentations

II.
REPORT

A. Cost Recovery (June 9, morning)

During the workshop, PG&E noted that cost recovery and cost allocation are related, but distinct issues. Cost allocation, for the purpose of this proceeding, refers to how the IOUs' DR costs are allocated among generation and distribution components of IOU rates. Cost recovery can also refer to how rates are designed to recover the costs that have been allocated to a given component. There was consensus among parties that the issue to be addressed in this proceeding is cost allocation. Cost recovery should continue to be addressed in the IOUs' respective ratemaking cases, such as General Rate Case (GRC) Phase 2 proceedings.

Two primary positions on this issue were represented at the workshop. DACC-AReM and MCE propose that, under most circumstances, costs for IOU DR programs be allocated to generation rates. DACC-AReM delivered a presentation (included in Appendix A) to summarize their position. The IOUs propose to continue their existing cost allocation methods, which spread DR costs among generation and distribution rates using various criteria.

ALJ Hymes posed three specific questions for conducting the discussion:

- What are the IOUs' current cost allocation methods?
- Should the current cost allocation methods be changed and, if so, how?

- What other factors, such as fairness issues and benefits, should the Commission consider if it changes the current cost allocation methods?

1. Current cost allocation methods

Parties generally agreed[4] that the characterization of each of the IOUs' cost allocation methods during the workshop was accurate. The IOUs' allocation methods for DR costs are described below. Parties also generally agreed that there are differences in how the IOUs allocate their DR costs among generation and distribution rates. CLECA noted that since 2002, for PG&E and SCE, their DR cost allocation and recovery methods were often developed in settlements, which has resulted in some of the inconsistencies, but that the differences between the IOUs are not large.

a) PG&E

The majority of PG&E's DR program costs (including most program incentives) are allocated to distribution rates. PG&E's Aggregator Managed Portfolio (AMP) contract incentives are the only DR incentives and costs allocated to generation rates. With the exception of dynamic pricing tariffs, all customers are eligible to participate in PG&E's DR programs.

b) SDG&E

The majority of SDG&E's DR program costs are allocated to distribution rates. Incentives for SDG&E's DR programs are allocated to generation rates. For SDG&E's dynamic pricing programs, D.10-03-032 directed SDG&E to allocate program costs to generation rates. Those costs had traditionally been allocated to distribution rates.

c) SCE

SCE bases its DR cost allocation method on eligibility for its DR programs. Costs for programs for which all customers, including DA and CCA customers, are eligible are allocated to distribution rates. Costs for programs for which only SCE's bundled service customers are eligible are allocated to generation rates.

2. Future cost allocation methods

There are two primary positions on this matter. The IOUs propose to continue their current cost allocation methods (mostly through distribution rates). DACC-AReM and MCE request that the Commission require the IOUs to allocate all costs for DR programs

[4] TURN clarified that they generally agree with the characterization, but that they had not retained their rate design expert to review the IOUs' testimony on the issue.

to generation rates. These positions are described further below. A third proposal that Shell Energy raised is also described below.

CLECA noted that it is difficult to determine future cost allocation methods because the policies for the future of DR, including bifurcation, have not yet been established in this proceeding. Several parties agreed with that point, though DACC-AReM and MCE suggested that the Commission can establish cost allocation principles now and apply those principles in the future. In its presentation, DACC-AReM also noted that this issue should be addressed now because it is a foundational issue in the proceeding, D.12-04-045 directed that this proceeding should decide the issue in a consistent manner across all three IOUs, and there should be uniform cost allocation principles. The DACC/AReM presentation is included in Appendix A.

a) Maintain current DR cost allocation methods

In general, current DR cost allocation methods recover DR-related most expenses via distribution rates. There are differences in cost recovery; however, among the utilities (for example, some DR-related incentive payments are recovered via generation rates).

b) Allocate all DR costs to generation rates

DACC-AReM and MCE propose to allocate all costs for DR programs to generation rates. DACC-AReM and MCE presented several concerns with the current cost allocation method:

- Artificially depresses generation rates, which gives the IOUs a competitive advantage
- Discourages participation by third parties in DR
- Conflicts with unbundling rules established in D.97-08-056
- Creates inappropriate cross-subsidies (from DA and CCA customers to IOU customers)
- Conflicts with Commission policy of competitive neutrality

c) Allocation based on categorization of resource

Shell Energy proposed that costs for supply resources be allocated to generation rates and cost for load modifying resources be allocated to distribution rates. SCE opposed this proposal because the concept of bifurcation is nascent and it is not yet determined which DR programs will be in each category of resources. SCE also noted that just because a DR program is categorized as a Supply Resource that does not mean it does not also have transmission and distribution benefits.

3. Factors for the Commission to consider

Parties discussed several factors that the Commission should consider if it decides to modify the cost allocation method for DR costs.

a) Fairness

DACC-AReM stated that their proposal achieves a "level playing field." SDG&E questioned what a level playing field means.

b) Function

CLECA recommended the Commission consider the function of a DR program when determining how to allocate its costs. TURN suggested that there may be some relevance in looking at why a program is dispatched, such as for distribution benefits, system benefits, or local reliability. SCE suggested that focusing on function of a DR program may not help because programs serve multiple functions (e.g. reducing generation needs, alleviating transmission congestion, etc.). CLECA agreed with SCE's point.

c) Benefits

TURN stated that while the function of a DR program has some relevance, it makes more sense to look at the benefits of a DR program. TURN stated that benefits certainly go to participating customers but that there also benefits to others by treating it as an alternative to generation. TURN also pointed out that there are benefits in terms of reliability for the entire system that all customers experience.

CLECA pointed out that DR, even if it is being used as a substitute as a generation resource, has benefits to the transmission and distribution systems. DACC-AReM acknowledged that point, but also noted that the same can be true of all generation resources or DSM programs offered by ESPs. DACC-AReM stated that while there are benefits other than replacing generation, the primary purpose of DR is to replace generation. TURN stated that because DR is primarily a capacity program, its primary purpose is to replace the equivalent of combustion turbine. CAISO stated that DR can be used for system or local reliability.

ORA stated that DR is at the top of the loading order and that all customers experience reliability and environmental benefits. ORA's position is that DR program costs should be spread across all customers unless a party can demonstrate that they do not benefit from DR programs. AReM stated that ESPs and CCAs can deploy interconnected solar but only their customers pay for that even though it has benefits for the entire system.

d) Obligation

SDG&E raised the question of whether ESPs and CCAs should have the same DR obligations as the IOUs. DACC-AReM stated that it depends on whether the Commission wants to move in that direction. PG&E suggested that whether the Commission has the jurisdiction to impose DR obligations on third-party LSEs would have to be considered.

SCE stated that a fundamental question is whether the IOUs' have an obligation to procure DR, because it is at the top of the state's loading order, on behalf of all customers or just bundled-service customers.

e) Jurisdiction

During a discussion about whether the Commission should apply the Cost Allocation Mechanism (CAM) to allocate DR program costs, MCE noted that the CAM is authorized by statute for certain purposes. Several parties noted that Commission does not have jurisdiction regarding a CCA's procurement, so a CAM-like cost allocation approach may not carry any weight for CCAs unless it was required by statute.

f) Customer eligibility

MCE stated that it is important for the Commission to consider eligibility. As an example, MCE noted that its customers pay for PG&E's dynamic pricing programs (SmartRate and Peak Day Pricing) but are not eligible to participate in those programs. CLECA stated that CCAs use IOU billing systems and that if they want to offer their own dynamic rates and avail themselves of using the IOU billing systems. AReM suggested CLECA's point is not relevant because CCAs pay the IOU to use their billing system. PG&E noted that there are certain systems and parts of an organization that serve all customers and that it does not make sense to talk about such systems in terms of allocating DR costs.

MCE stated that if the costs for an IOU DR program for which CCA customers are not eligible are allocated to all ratepayers, and a CCA wants to offer a similar DR program, the CCA customers will be paying twice for one program. CLECA suggested a way to help mitigate this issue could be to separate allocation of program administration costs from allocation of costs for incentives.

g) Other Issues

Shell suggested that supply resource DR is a competitive service and that the IOUs should be excluded from offering supply resource DR due to Affiliate Transaction Rules. PG&E disagreed that Affiliate Transaction Rules apply in this situation to IOU procurement. ALJ Hymes stated that parties who want to discuss Affiliate Transaction Rules should do so in their briefs.

B. Back-up Generation (June 9, morning)

The Back-up Generation (BUG) Policy was stated in D.11-10-003. NRDC stated that CPUC's policy does not give credit for BUG for DRP but understands there is a suite of programs for different purposes. NRDC is open to understanding the objectives of programs.

CLECA noted that D.11-10-003 (at page 30) stated that the policy will not be implemented until further study and to their knowledge there are no further studies on the matter. It was also noted that other agencies (e.g., federal, state and local) already address use of BUG and there was concern that we could be throwing out resources. PG&E expressed the same concern about the "lost MWs" and had proposed additional studies be conducted in their testimony. JCI recommended that since BUGs are regulated and there is a requirement to run them (e.g., test runs); why not let the BUGs test runs coincide with DR events.

TURN believes that the PUC has the authority to require that customers not use BUGs in the context of DR and whether they should be used for DR to meet the loading order. EnerNOC also stated that the EPA RICE regulations governing reciprocating combustion engines limit their use, but there can be exemptions that CAISO can determine (e.g., emergencies). The PUC could require generation owners (those who have BUGs) to report and justify their use of BUGs for DR (e.g., emergency).

PG&E stated that if third party participants through Rule 24 were to register a customer for whole sale bidding, and do not go through the IOUs, then there is no PUC regulatory means to regulate. Energy Division pointed out that if the RA was sold to an LSE, then the PUC would have jurisdiction.

At the conclusion of the discussion, ALJ Hymes determined that the use of BUGs was a policy issue; all parties have provided their positions in their testimonies; and it is now a matter for the Commission to determine policy.

C. CAISO integration costs (June 9, afternoon)

1. Presentations of CAISO Integration Costs by Parties

Each of the three utilities, PG&E, SDG&E and SCE provided presentations that described the considerations and basis for their cost estimates to integrate their systems with the CAISO. The cost estimates are contained in the IOUs' June 2, 2014 Applications for implementation of Rule 24.

Other parties, EnerNex (on behalf of the CAISO) presented on the costs that are anticipated by the CAISO for CAISO market participants. The Joint Parties also presented their perspectives that included their costs that would be incurred for interfacing with the IOUs for customer information and to provide required data to the CAISO; and their costs for customer engagement (e.g., incentives, performance monitoring during events. The Joint Parties also presented a comparison of other ISO market requirements and CAISO requirements. CAISO requirements increase costs and risk to market participants.

Appendix A includes presentations provided by parties during this discussion.

2. Discussion of CAISO Integration Costs

A panel discussion comprising of the IOUs, Joint Parties, and EnerNex followed the presentations. Other parties asked clarifying questions of the panelists and the CAISO.

PG&E explained that its cost estimates for Rule 24 includes costs based on full compliance with the requirements of the current CAISO tariffs, although its actual request is based on a more limited manual approach in light of the uncertainties from the recent D.C. Circuit decision (Energy Power Supply Association v. FERC). The CAISO asked why PG&E looked to the CAISO tariffs, since things are changing constantly. During the discussion, PG&E pointed out that there are other costs outside PG&E's pending Rule 24 application, including MRTU-related costs (PDR 1) that have already been incurred, and costs described in its DR OIR testimony, chapter 3 (PDR 2), which have not been requested in any proceeding yet.

SDG&E described its Rule 24 application approach as using a manual registration approach and working with resources under 10MW. SCE's costs anticipate receiving selected waivers from CAISO requirements.

Discussions primarily centered on understanding CAISO requirements particularly telemetry requirements, frequency of meter data communications (e.g., every 5 minutes), and the costs that are associated with these requirements. The Joint Parties discussed their use of their systems and raw operating information to monitor customer performance relative to their commitment to the IOUs so that they can provide feedback to the customer to meet delivery commitments. Comverge stated that the New England market had 1200MW of demand response, which has fallen to 300MW with no prospect of growth, due to requirements such as local dispatch and must offer requirements.[5] EnerNOC stated that if settlement is based on performance within a sublap, it will only want good performers. SCE indicated that the CAISO single Load Serving Entity (LSE) limitation is causing them to strand lots of DR.

More understanding of requirements for CAISO market integration is needed before better cost estimates can be offered.

[5] At the request of the workshop participants, the representative from Comverge provided the "Other ISO Summary of Demand Response Providers Operating in Other ISOs and Key Market Characteristics" included in Appendix A to this report.

D. Bifurcation/Categorization of load modifying resource and supply side resource demand response (June 10, morning and afternoon)

A participant from the CAISO provided the following summary of characteristics for supply resource DR and characteristics for load modifying DR resources, based on their view:

	Load modifying resource (LMR)	Supply resource (SR)
Dispatchability	Dispatchable by IOU	Dispatchable by ISO
Relation to resource adequacy requirement	"Value": can reduce RA requirement	"Credit": can meet RA requirement
Bidding into ISO	Cannot be bid into ISO	Can be bid into ISO (CLECA) Should be bid into ISO (CAISO)
Trading/fungibility	Cannot be traded, cannot be substituted for a generating resource	Can be traded

1. Value vs. credit

The parties agreed that Load Modifying Resource (LMR) DR has RA value and can *reduce* the resource adequacy (RA) requirement, while Supply Resource (SR) DR can *meet* the RA requirement (that is, it can count towards "RA credit"). They also generally agreed that the magnitude of the RA value of LMR DR should be consistent with the RA credit that SR DR receives.

TURN expressed concern that if a DR resource meets RA requirements, then that DR resource should be displacing new generation, but this may not always be the case.

2. <u>Load and resource forecasts</u>

All parties agreed on the need for clarification as to how the California Energy Commission's (CEC) load forecast is impacted by DR programs and by the bifurcation of DR into LMR and SR. Double procurement should be avoided. It was generally acknowledged that CPUC definitions for RA and CEC load forecasting methods have been changed in the past.

PG&E noted that every April, the IOUs file their annual Load Impact Reports, which are used to determine the capacity value of DR for Resource Adequacy (RA) and Long-Term Procurement Plan (LTPP) purposes. Most DR is normally counted as a supply-side resource for CEC's forecast which reduces the amount of new generation procured in the RA and LTPP proceedings. For most DR programs, load reductions are added back to the load data so the CEC's load forecast is established without DR called. The CEC recently reclassified IOU Critical Peak Pricing and Peak Time Rebate programs as demand-side programs (and therefore should reduce the load forecast), but if the CPUC counts the RA value of these programs, then these programs would be double-counted. The ALJ noted that RA rules would not be changed in this proceeding. However, EDF and PG&E pointed out that if guidance on the treatment of DR programs in the context of RA is not provided in this proceeding, these issues would not be addressed in the RA proceeding.

CLECA expressed concern that if we have LMR that doesn't impact the load forecast, we will procure RA from generators, and ratepayers will pay more than they should.

SDG&E noted that we should keep weather normalization that may impact the load or resource forecast in mind. They were concerned that LMR may or may not be included in CEC's forecast.

CEC noted that the proper forum for this discussion is the Demand Analysis Working Group (DAWG). CEC noted that the topic is on the agenda, and acknowledged that if the CPUC plans to go forward with bifurcation, then there would need to be an adjustment in how CEC does its forecast.

PG&E, the CAISO, and EDF agreed that there needed to be clear guidance from LTPP and RA proceedings rather than solely relying on the DAWG. Specifically, we need to know if LMR is or is not able to reduce the need to procure new generation. CAISO and EDF agreed.

3. Dispatch at coincident peak

PG&E said that DR does not need to be actually dispatched at the coincident peak but only needs to be available during the hours required by CPUC to qualify as a RA resource. PG&E has AMP program which counts, is callable at all hours in the contract, can't be withheld, and CAISO can dispatch if needed. If a LSE does not dispatch a DR resource during the coincident peak, it is because there are lower cost resources that can meet the load. In the last few years of mild summers and a slower economy, PG&E did not dispatch all of its RA resources (both DR and generation). EnerNOC supported this point. PG&E is paying for various DR programs because they have RA value. If they did not have that value, they would procure less of that DR and they would have to procure some other resource which would have an ultimate impact on ratepayers.

Both EnerNOC and SCE pointed out that it is impossible to predict the coincident peak in advance. The CAISO believes that it is the responsibility of the LSEs to manage their LMR DR programs. TURN agreed that there is a lot of excess capacity right now so often there isn't a need to dispatch DR. However, in the future, we will likely need to dispatch DR more regularly so we should discuss how to get there.

CAISO did not agree that LMR DR can count at full capacity value if the DR is not dispatched at full value during the coincident peak. If LMR DR does not reduce the coincident peak then it is not providing full RA value. The goal of DR is to use DR resources when the peak comes, that is "in the spirit of the loading order". The RA value of LMR DR should be based not on the potential of a program but what it actually did.

SCE stated that DR must be available at all hours for which it could be produced; in other words, no withholding is allowed.

TURN pointed out that RA is a one-year construct. RA is not replacing need for LTPP for purposes of new construction. TURN also indicated that DR may need to be dispatched more often, if we don't have the same extra [generating] capacity as exists now.

The CEC argued that frequent dispatch of DR should create customer fatigue over the long run. PG&E pointed out that fatigue may not occur, and has not been a significant problem. CEC responded that may be true for now, but CAISO is looking for more frequent dispatch in the future.

Discussion noted that supply side DR must be there and offered, with the market dispatching based on price. So DR dispatch as supply side in the CAISO market may not occur on the peak either.

4. CAISO integration

The CAISO argued that their $200 million software (MRTU) exists to perform decision optimization regarding dispatch, transmission, d-rates and other factors. The CAISO encouraged IOU's to bid their DR resources as SR, and let the system optimization work, because then they would account for full RA value.

PG&E acknowledged that CAISO has more complete wholesale market information than IOUs, but contended that it was simply too costly – and sometimes infeasible – to bid all of PG&E's DR programs into the CAISO. Once DR resources are split by sub-LAP and load serving entity, many resources will be less than 100 kW and cannot be bid in. Also 20% of PG&E' BIP customers are Direct Access (DA) customers and could not be registered into the ISO for bidding BIP, unless their DA provider approves the registration.

Olivine also noted that it would be hard if some part of a given program could be bid in (e.g., >100kW portion of CBP) but the other part cannot be bid in (e.g., <100kW portion of CBP).

5. Non-coincident peak and distribution value

Many parties pointed out that a focus solely on the coincident peak is problematic because there are also local reliability needs, flexible capacity needs, over-generation needs, and distribution-level needs that DR can meet.

The Sierra Club pointed out that DR can help with intermittent resources and helping with distribution system stability. The CAISO indicated that distribution system operation is going to change, and there will be situations where one resource will need to have two masters.

The Clean Coalition claimed that not every utility will see the value of DR in the same way. There may need to be an attempt to harmonize these different valuations.

Marin Clean Energy wants to engage in and administer cost-effective DR programs, but is unclear how this will impact their RA requirements and how the benefits of their peak reduction would be tied back to the LSE.

CAISO noted that in the future there will be many other LMR-like resources modifying load, such as distributed generation, storage, etc. that won't get RA credit or be bid into CAISO market. These other load modifying distributed energy resources should be considered when writing the rules for DR.

SDG&E asked how you would handle valuation in an over-generation situation.

E. CAISO Must Offer Obligation (June 10, afternoon)

1. Availability vs. dispatch

Several parties expressed concern and confusion regarding the CAISO's Must Offer Obligation (MOO) for supply-side DR resources, e.g., whether bidding into real-time market would be required, how frequently would DR be dispatched under MOO. EnerNOC proposed an alternative to a MOO in which supply-side resource DR would be a call option based on a predetermined price with consideration of dispatch frequency.

Other parties, including the IOUs, TURN, and CLECA raised similar concerns about the fact that LMR DR should be valued for its availability, not just for when it is being dispatched, similar to a generation source that is not dispatched during the coincident peak yet given RA credit.

The CAISO explained that the Use-Limited Resource MOO in CAISO is "as available" and that if a resource is not picked up in the Residual Unit Commitment (RUC) it will need to participate in the Real-Time Market (RTM). (A MOO is not expected for RDRR.) If resource is not picked up in RUC and has a notification time of over 5 hours, it would have no RTM obligation. But does DR have RA value if it can't be in real-time.

The CAISO added that it was unclear as to why this would be "onerous to DR" and stated that DR resources should not be compensated merely for their availability but based on dispatch during coincidental peak. CAISO also stated that this issue does not belong in a CPUC proceeding because it is a CAISO stakeholder initiative. PG&E clarified that the current RA availability requirement is all non-holiday weekdays but the operational requirement is three days in a row up to 24 hours. When pointing out that the CAISO's MOO is not yet finished, the CAISO confirmed. PG&E also pointed out that defining SR DR is complicated and requires sufficient time and urged the Commission not to rush DR to supply side before knowing all the implications. PG&E requested that LMR DR should have value for reducing the RA requirement.

Sierra Club stated that the essential debate is what is dispatched through the CAISO, and what is not. Can there be LMR DR that is dispatchable but not visible to the ISO? Several parties voiced the concern that the CAISO's processes would not prevent the CAISO from using DR prematurely. EnerNOC asked how availability translates into MOO. If you have a use limitation, what does that mean for availability? SCE said that bid price is what is used to manage availability. SCE also asked how MOO accommodates customer tolerance.

The CAISO stated that is why the DR resource's Use Plan is so important - so the CAISO can make sure it has enough resources to meet its projected needs. The use plan needs to be updated monthly. The DRP can bid at whatever price they want. Several parties asked the CAISO about the Use Plan and what it is.

Jt. Parties said there are a lot of disconnects and are concerned that CAISO rules may change, and process now may reduce DR.

SDG&E asked whether the load forecast is normalized for weather, by taking into account that DR was not needed in cool year but will be used in a hot year.

EnerNOC added that resources provide operational flexibility for IOUs. If the CAISO insists that DR has to operate at system peak, it is difficult to predict that perfectly. If that is the only criterion, the DR resource will be devalued.

PG&E asserted that the ISO can dispatch resources a little more precisely than IOUs but it costs a lot to implement, and the IOUs cannot bid DR into the CAISO market if the customer's LSE won't allow it which can sometimes make it difficult to meet the 100 kW minimum requirement for Proxy Demand Resources (PDR) by sub-LAP and LSE.

2. Strike price

SCE mentioned that a strike price is a challenging concept. The current markets have a price cap of $1000 to protect customers, but this prevents DR customers from showing their opportunity cost in the CAISO market. SCE also asks how does MOO accommodate customer tolerance, but CAISO responded that MOO is based on a resource, not customers.

The CAISO stated that it is incumbent upon the DR provider to develop a stable of participants to manage the strike price of a DR resource. This may require them to sign up more customers to manage this risk.

CAISO mentioned that a use-limited resource must submit a USE Plan that indicates what the availability of that resource is. The CAISO suggested EnerNOC and SCE would have to have these kinds of discussions in order to figure out the strike price, since this is for the DRP to solve, not the CAISO.

TURN expressed concerns with participants, such as AMP customers, bidding at very high price to hold out and thus potentially never bidding in or being dispatched.

The CAISO asserted that there is no price requirement for DR. For system RA, the requirement is to self-schedule or fulfill the MOO. For flexibility, the MOO requires economic bids. There is nothing in market power mitigation to mitigate bids for PDR.

3. Use plan and availability

Several parties including CLECA and PG&E requested clarification from CAISO on the use plan and scheduling bids. The CAISO responded that an accurate use plan is crucial since the DRP has an obligation for use plan to bid during time of availability. The CAISO referred to the Commitment Plan Enhancement Stakeholder Initiative in which these issues are being addressed in more detail.

The CAISO was asked about use limitations and how that would translate into availability for MOO. The CAISO stated that it may not accept contract limitations as a valid use limitation. CAISO also might not accept use limitations based on economics. Operational and environmental limitations might be allowed.

4. Reliability Service Initiative (RSI)

The CAISO has a stakeholder initiative on the Reliability Services Initiative (RSI), which is currently in the process of review. At this point, it is not sure if the CAISO wants to put strict MOO's on DR. The Standard Capacity Product (SCP) is being developed to incent DR to be available. The CAISO stated that it would rather incentivize DR resources to participate than mandate.

5. Amount of DR

TURN stated that it is concerned that AMP contracts will not be dispatched if the strike price is too high. Assuming contractual limitations will be accepted as use limitations by the CAISO, it appears that they would not dispatch.

The CAISO said that questions about customer strike price are up to the IOUs and demand response providers. SCE commented that bid price is what would be used to manage availability. EnerNOC claimed that if the market is clearing at $50-60/MW on peak, then DR would not clear 98 percent of the time.

There was general agreement among the parties that DR would not necessarily be dispatched more often under this new scenario.

SCE suggested analyzing the most valuable hours and their opportunity cost in order to find the appropriate bid price that will value those top hours.

6. Day ahead vs. real time

PG&E requested clarification from CAISO on whether customers are expected to participate in both the day-of and real-time markets and expressed concern for such requirements since some customers may not be able or willing to participate in the real-time market. This information should ideally be shared sooner than later in order to communicate such a drastic change to customers.

CLECA requested the CAISO to consider economic and possibly contractual constraints to be included in use-limitations and asked for a concrete timeline and plan for these issues to be discussed. The CAISO responded that the startup time might be a factor in this decision.

CAISO clarified that when a DRP dispatches a PDR it will be tested to determine the maximum amount of load reduction (Pmax). If a DRP plans to have less load reduction available than its Pmax, they can bid a reduced amount into the day-ahead market.

EnerNOC also brought up the issue of changing peaking needs in our system, which requires definition for the DR providers to submit their supply plans.

Olivine stated that it would be preferable not to have DR in the real time market due to logistical and technological constraints, yet that would also mean that it would not provide as much value in the day-ahead market alone, since the day ahead market never clears at prices as high as in the real time market. By not requiring the DR to bid into the Real Time market, we diminish its RA value.

The Joint Parties expressed concerns from the DRP's perspective that the CAISO integration (*or just MOO?*) does not seem as much a policy to grow DR but shoving DR into a box in which it does not fit and very well could shrink instead of grow. The IOUs and CLECA agreed, and many others present nodded in agreement.

CLECA added that DR is at the top of the Loading Order. The Commission wants to grow DR. Under the bifurcation rules, there is a risk that LMR DR will have reduced value. Need to make changes in RA carefully and deliberately.

F. Demand response goals (June 10, afternoon)

1. Approaches to goals

a) Needs-based

SCE points out that the world has changed, so goals must be need-related, based on market potential, and value. We must know the rules, how dispatch will work, etc. Any DR goals could be needs-based and defined on a portfolio basis (different price points, dispatch criteria, etc.). For example, it might be useful to recognize where reliability DR is more valued than price-responsive DR. 100 MW of local DR may have more value than 200 MW in another area. We are looking at the art of the possible; there are finite groups of participants, and a pattern of frequent migration by customers from one alternative to another may not be desirable. We need a DR market potential study (similar to ones that are done for regularly for in the energy efficiency proceedings).

SCE stated that goals can create adverse incentives; goals must be more thoughtful. Would DR meeting the cost effectiveness level be what you would want to do?

EDF, Sierra Club want opportunity cost approach, that includes value on a time and location basis, and advocate for transparent prices to unlock value.

ORA generally supported SCE's position. TURN agreed that there should be some needs-based goals. CLECA also stated that the goal should include maintaining reliability-based DR. It was good to have BIP on February 6, 2014, when it was needed to protect the system. Need to keep DR for that purpose.

EnerNOC pointed out that DR is not a monolithic resource, and it has many different uses. There is a need to look at all the different types of resources (contingency, emergency, flexible/peak capacity, etc.).

PG&E said it is too early to put out a number as a goal. We need to determine how to capture all cost-effective DR and new value, and define new products including how to handle over-generation situation.

SCE reiterates that DR has lots of variety. How does it fit in new market? Programs are only 3 years currently. SCE repeated the question of what problem(s) is DR trying to solve? Greenhouse gas reduction? Flexibility, to integrate renewables?

b) Opportunity-based (maximize cost-effective DR)

Sierra Club seeks to develop an opportunity-based approach where all cost-effective DR is procured. One goal should be to remove all barriers to DR and making DR more available with market mechanisms and have consumer friendly programs. Sierra Club also noted that emergency DR is capped in CA at 2% while in PJM it was 14% (being pared down to 10%). It considers 2% to be too conservative.

Others commented that cost effectiveness should be tied to avoided capacity costs. Could avoided capacity costs be tied to value as opposed to using weighted average cost bid in the DRAM?

EDF generally agreed with this approach and seeks to maximize the value of DR from the distribution level to the system level by placing an explicit value on the time and location benefits of DR. EDF stated that granularity and transparency in the quantification of these benefits is needed.

PG&E said it was too early to set goals for DR, but agreed we should be procuring the maximum amount of cost-effective DR and noted that there are things the IOUs, CPUC, and CAISO can do to reduce costs and risks while increasing the value of DR.

Marin Clean Energy would like all LSEs to be able to offer DR programs. They cautioned against an obligation for IOUs to achieve a MW-value goal because this creates a compliance problem for non-IOU LSEs. There is some value in having targets but less in having obligations.

c) Planning purposes

Clean Coalition contended that real targets were important for planning purposes so that the IOUs will know what to procure. It would be good to incorporate cost effectiveness and targets in a way that improves overall planning, and provide the best deal for ratepayers and the environment. In line with the Loading Order, *all cost-effective DR* should be procured, not just the least-cost DR.

CLECA contended that while DR programs are of critical importance to the overall system and distribution grid, it may be premature to establish targets.

2. Sanctions

ORA raised the question if a utility did not meet its targets, would there be sanctions? Most parties generally agreed that sanctions for IOUs not meeting DR goals are premature. EnerNOC agreed but acknowledged they do provide guidance for procurement.

3. Conflicting goals

SCE noted that there is a finite set of customers who can play in the market, and they wanted to avoid a situation where customers are merely migrating from one program to another versus growing the DR customer base.

ORA was concerned over how an IOU decides which RA resource to procure when cost came into conflict with goals. CAISO agreed with this point, asking how an IOU would weigh competing goals such as RPS, DR, and least cost procurement.

PG&E noted the discussion on goals had crossed into RA, LTPP, ratemaking and other topics. Ratemaking and rate design involve a lot of other considerations (such as covering the authorize revenue requirement, statutory requirements.) Ratemaking policy should not be mandated in isolation outside of rate design proceedings. PG&E noted that there should be concern for customers and impacts.

4. Long-term plans

PG&E expressed concern that for DR to displace a long-term supply resource in the LTPP, it should be paid in a similar manner to those supply resources. Right now, RFO's have long contracts of 10 to 30 years, while DR can only be done in 2-5 year chunks. Yet, shorter term DR contracts make sense in some regards because PG&E is able to take advantage of new technologies and economies.

5. Cost effectiveness

Clean Coalition contended that the loading order says that cost effective preferred resources should be procured rather than the lowest cost preferred resources. CPUC noted that in the public utilities code, there is some constraint with respect to the need for a diversity of resources, but least cost resources are not necessarily required. SCE said they seek out "least cost, best fit" resources when procuring for a specific need as opposed to looking at cost alone.

EnerNOC was concerned that cost effectiveness methodology was not keeping pace with the needs that DR is expected to fulfill. EnerNOC also stressed that DR is a customer resource, and that there should be more certainty for customers and less changes of rules.

CPUC staff mentioned PUC section 454.5 criteria in considering portfolio: diversity of supply, not just least cost. SCE mentioned "least cost, best fit", stating it is more of an optimization equation, a need portfolio.

G. Demand Response Auction Mechanism (DRAM) and Cost Effectiveness Protocols – (Part I) (June 10, afternoon and June 11, morning)

On the afternoon of June 10, 2014, Rachel McMahon and Joy Morgenstern from the Energy Division held a combined workshop and Q&A on the DRAM (McMahon) and Cost Effectiveness Protocol (Morgenstern) to continue the conversation on issues raised in the April 28, 2014 DRAM workshop as well as incorporate how the new cost effectiveness protocols (CEP) developed by Ms. Morgenstern would impact the DRAM and vice versa. Since the April 28 DRAM workshop, the Energy Division has refined some of the DRAM design to accommodate issues brought forward by stakeholders.

1. DRAM cost cap and weighted average calculation

McMahon explained that the ultimate cost cap is being determined by a weighted average of all qualifying bids. Each proposed bid/contract will be evaluated for cost effectiveness individually. A bid is deemed approved if it wins below the cost cap *and* is below the cost effectiveness evaluation. Respectively, if the bid passed the cost cap but is above cost effectiveness threshold it would not be approved.

Several parties raised concerns about the methodology proposed in the April 28 workshop, in particular the weighted average calculation and cost cap.

EnerNoc asked whether the Energy Division has calculated an avoided cost for flexible capacity resources since the proposed protocol has some discussion of flexibility and how it could be included in the calculation.

CLECA proposed getting paid up to a certain price instead of capping it using the weighted average of bids. McMahon asked what that point would be. CLECA responded that that would have to be determined. CLECA also noted that in the Renewables

Auction Mechanism (RAM), bids were weighted by hour of delivery. Hence some sort of metric should be considered for the DRAM.

Question about what prices are you looking at: wholesale prices or retail rates?

2. Cost effectiveness protocol

Ms. Morgenstern explained that the new cost effectiveness protocol (CEP) will be released soon and will be bifurcated for LMR DR and SR DR. Ms. Morgenstern stated that the new CEP will largely apply to load modifying DR (LMDR). The primary methodology is to calculate the avoided costs of DR displacing a power plant. These avoided cost calculations apply to all demand-side resources (DG, EE, etc.); relate to capacity, energy and transmission and distribution (T&D) costs avoided by any demand side resource; and are projected out for 25 years. For DR, the primary value is avoided generation capacity (value for avoided T&D costs and GHG benefits would follow). She further explained that they take characteristics of the DR programs into account, such as the availability time, local and flexible DR among other adjustment factors, and use these to create a benchmark.

CLECA suggested that the CEP may not be refined enough yet. Morgenstern agreed that the CEP is not sophisticated enough and that it needs to be modified in the future.

SCE pointed out that the model for CE builds on a price duration curve, but DR programs are not constructed around that paradigm. Staff indicated that the model doesn't really deal with supply-side DR. It's only supply-side use is in the DRAM.

Sierra Club asked whether a reasonable person will be able to interpret the CEP and have access to the information. The Energy Division confirmed that the CEP is public information available on the CPUC website, while the DRAM methodology is not.

To TURN's question whether the protocols apply to the capacity bidding program, Ms. Morgenstern responded that this is what they would use for any kind of DR. SCE asked whether there will be a local capacity constraint adder to which Morgenstern responded that there may be an adder for local constraints.

3. Demand response and over-generation

CLECA asked whether the use of DR for overgen is being incorporated in the calculations. Morgenstern asserted that in theory it is included in the avoided capacity cost calculation (based on a marginal power plant), though she conceded that such future scenarios need to be further discussed and potentially revised in the CEP. Sierra Club was concerned about low bids.

CAISO interjected that overgen needs to go through two different assessments since it would provide a negative value to DR due to negative prices. Morgenstern stated that the Energy Division will need to modify the model for overgen to account for this challenge.

SCE asserted that their DR programs are not constructed for overgen since it involved a completely different kind of customer. Furthermore it would be important to define when you want to increase load and that it should be accurately reflecting the prices of demand and supply.

4. Market failure

Sierra Club asked whether the Energy Division has an idea of how many bidders there will be and whether they are worried about market power. Furthermore, they brought up concerns associated with the RAM in which low bids were prevalent. CLECA also expressed concerns about real world ramifications if and when we are unable to get more DR at a lower cost. McMahon shared the parties' concern about low bidders and affirmed that DRP would not bid at such a low price and deliver. The Energy Division is not proposing the cost cap to go down over time. TURN raised the issue that bidders could bid lower in the CAISO market than their original bids for the DRAM. CAISO responded: No Location Marginal Price (LMP) for PDR (RDDR and PDR).

McMahon acknowledged the possibility of system gaming raised by Sierra Club, CLECA and SCE and explained that bid mitigation provisions have been designed to exclude bids that seem disproportionally high and allow IOUs to reject any bids if they suspect market manipulation (e.g. entering bids for customers that do not exist or very high bids). She furthermore, stated that unlike in the RAM, bid viability, demonstration and deposits are not required for the currently proposed DRAM. Since there was a robust supply of providers in the RAM, she is hesitant about setting too many criteria for the DRAM, which could discourage new actors from participating.

In response to parties' voiced concerns, McMahon admitted that they could end up in a scenario with bids that are not as cost effective in which case they would not ratchet it down. CLECA expressed concerns with the weighted average approach since it would not ratchet down the price as it did in the RAM. If we are trying to grow DR, we would need to ratchet down the price. McMahon's response was that we could get a scenario with very high cost cap as well.

SCE expressed strong concern about unusually high bids, which McMahon was unable to clarify. SCE stated that IOUs and 3rd parties are duplicating efforts for CAISO integration. In response, McMahon suggested a pilot for the first year in transition to moving toward Rule 24/3rd party participation. SCE pointed out that in a competitive market with high entry cost, players will attempt to avoid high entry costs.

ORA pointed out that due to existing AMP contracts, how will the DRAM be a robust auction if the best customers are already taken? ORA went on asserting that we need to make sure there are as many customers as available, during the first year, the auction would be more the nature of a pilot.

Parties raised the issue that DR customers (for instance AMP), would have to leave the program in order to sign up with another program, which may seem unappealing in the beginning. ORA and McMahon responded by saying that customers could stay with their current provider (Aggregator, DRP or IOU) until DRAM bid goes through and then switch. McMahon challenged that if we continue with utility DR, how would we incentivize 3rd parties to participate? The ALJ interjected by stating that the IOU's role in the future has been included in the scope.

SCE questioned the overall need for the DRAM. If it is cost effective for DA and IOUs to procure DR they would be doing this in the first place? McMahon explained that the DRAM is being created since we do not have a centralized competitive mechanism and need to create a market outside of utility programs. Reference was made to the Joint Reliability Plan (JRP); however proposals are not released yet.

5. Local and flexible demand response

As a result of the April 28 workshop discussions, in which parties suggested holding separate auctions for local and flexible DR in order to assign them with an individual value, the Energy Division proposed individual "buckets" for local and flexible DR (within a large "pool" of system DR) that would have a separate cost cap. Morgenstern affirmed that local and flexible DR is worth more, though conceded that they do not know how much more at this point. CAISO specified that it does not require both flexible and system DR. Local DR qualifies for system DR.

TURN expressed its support of the weighted average calculation since it is based on calculating avoided costs and Supports identifying a way to encourage competitive pricing below the cost effectiveness proxy.

SCE also brought up a concern about the utility's role and cost burden of this mechanism. They stated that utilities would just be buying an "RA tag" and questioned the need for the utility to be involved in this when Direct Access (DA) customers could participate directly. SCE asked why we cannot let the market handle this since CAISO markets are the ultimate recipient of dispatch value but utilities are bearing the excess cost or all participants (including DA).

TURN commented on the cost cap being strictly cost based ($/kW), which does not capture differences and nuanced values of bids. They raised the question of other characteristics that add value to the product.

Morgenstern responded that programs with similar features will be compared to each other. The "weighted" takes into account the different characteristics. At the same time, basing the individual bids on actual products could be problematic.

EnerNOC requested that characteristics for RA qualifications should be factored into this at a minimum.

CAISO annotated differences within the system, which require a standardized product in order to compare apples to apples.

H. Demand Response Auction Mechanism (DRAM) and Cost Effectiveness Protocols – (Part II) (June 11, morning)

On the morning of June 11, 2014, Ms. McMahon from Energy Division staff was present to further discuss the mechanics of the Commission's DRAM proposal. The discussion focused on five main areas: (1) Cost-Effectiveness consideration in the DRAM; (2) Emergency DR proposed in the DRAM; (3) Cost Caps and RA; (4) Goals for DRAM; and (5) DRAM Contract Bidder Requirements.

1. Cost-Effectiveness Consideration in DRAM

The Joint DR Parties inquired whether the DRAM includes a cost-effectiveness aspect because the Commission is expected to issue an updated cost-effectiveness model. The Joint DR Parties were trying to connect how the updated model would be used in the DRAM. Ms. McMahon explained that only the avoided cost calculation of the model will be used. CLECA discussed that it was their understanding that 250 hours used in determining the avoided costs and the A-factor would be updated in the new model. Ms. Morgenstern was not present at during the discussion; however, the ALJ recommended that parties request a Question & Answer session after the draft protocols are issued.

2. Emergency DR in DRAM

Ms. McMahon discussed how the 2 percent cap for Emergency DRAM was to align with the 2 percent cap adopted in D.10-06-034. CLECA expressed its concern that the Commission should not transition existing reliability programs to the DRAM because they are already scheduled to be integrated in the CAISO and no further changes are necessary. CLECA stated that the Commission should not force customers to move away from BIP which is a proven resource, to a new Emergency DRAM product which could increase risk in an emergency situation. SCE added that BIP is an important resource to the utility so that it can dispatch it during an emergency need. PG&E used the example of how the health system reacts to general influenza compared versus SARS and posed the question that the Commission would need to determine what level of reliability it wants and what it is willing to risk. PG&E pointed out that BIP has been very valuable and has high non-performance penalties.

PG&E notes that the DRAM was developed to build a DR market and that an Emergency DRAM market appears premature, because BIP is already moving into the CAISO market. PG&E recommends that Emergency DRAM be part of a later phase to the overall DRAM. Furthermore, PG&E points out that it would be difficult to get an Emergency DRAM to be consistent statewide like it is now. CLECA suggested that the Commission could conduct a pilot Emergency DRAM using a portion of PG&E's unsubscribed emergency DR MW cap adopted in D.10-06-034.

The Joint DR Parties are not supportive of preserving BIP, because it competes with third-party offerings. Joint DR Parties also commented that there needs to be a spectrum of DR services and determine how we value each. TURN noted the issue of having two streams of payment, BIP and Emergency DRAM. Although the DRAM payments could increase participation it would be useful to see price discovery through the program. TURN believes having concurrent payments for BIP and Emergency DRAM is counterintuitive and could lead to gaming but not sure how quickly the Commission can eliminate this issue by 2016. EDF agrees with Joint DR Parties and TURN.

3. DRAM Cost Caps and RA

Ms. McMahon agrees with Calpine that the vision of the DRAM was to function as an RA "tag." Calpine noted that the value stream would be monetized as it is in other markets. The Joint DR Parties added another dimension that the type of RA "tag" is important. Ms. McMahon discussed the difference in Market Clearing versus Pay-as-Bid pricing. She noted concern that if the Commission set a market clearing price, then it may be seen as setting wholesale price in wholesale market, which would be a problem under the Federal Powers Act. She noted that ERCOT only moved to market clearing price once they had experience with as bid.

Comverge stated that Pay-as-Bid initially would yield higher prices as providers try to recover upfront fixed costs and marginal costs, while payment of market clearing price should cause people to bid marginal costs. Clean Coalition expresses concern that the cost cap violates the loading order and will result in not taking all cost-effective DR. TURN states that having a separate cost cap is good because the E3 cost-effectiveness model will be the target. Comverge stated that price caps always create gaming but that having an average cost cap would be more beneficial than a straight cap. ORA supports a DRAM with a weighted average cost cap.

SDG&E says that maximizing the sources that participate in bidding should help minimize price.

The Joint DR Parties seek clarification how to have varying prices when there are standard products. Calpine inquired on how Energy Division would rank differences of bids. Ms. McMahon describes that to not complicate the process, the bids would be bucketed by IOU RA obligations (e.g., system, local, or flex) and then ranked by price.

Calpine questions why cost-effectiveness is relevant if bids are ranked on price. SDG&E questions why a separate DRAM is needed when procurement mechanisms already exist through all-source RFOs. Ms. McMahon explained that the DRAM is treated separately to increase market opportunities for DR, that after a few years it could fold into the Joint Reliability Plan with other preferred resources, and that the key is to really maximize it early on.

4. Goals for DRAM

Ms. McMahon stated that the 5 percent price-responsive goal of the DRAM is based on the CEC's adjusted load forecast so it will also be based on long term planning. SDG&E inquired why the goal is not to maximize cost effective DR if more than 5 percent of cost-effective DR was available. Ms. McMahon responded that it is a "soft goal" which is really to establish a MW number that would change based on the load shape (i.e., taking into account dynamic rates). CLECA pointed out that the old goals (5 percent) never took into account the cost to achieve them, and neither does the DRAM goal give the Commission a good signal is on what cost is to achieve the goal.

SCE recommended that the DRAM goal should be a subset of the overall goals established in the Rulemaking. ORA stated that any goals need to achieve what we have seen to date and that the goals should be based on need included in the long term planning process. EDF disagrees that it should be needs based, but rather value based: "what is needed, is it incremental?" The Joint DR Parties appreciates what it meant by need but that the goal should also include existing resources. SCE noted that commissioning a potential study will help inform the goal. The Joint DR Parties pointed out that if we are not achieving potential, then we should determine what is preventing it. CLECA stated that a goal would need to look at DR on a locational level and the need of the grid and it is not clear how that would play into the DRAM.

There are two types of needs, a) end use customers, and b) geographical areas. Mr. Kaneshiro with Energy Division commented that Staff is working on a contract for a consultant study to determine DR potential and needs.

5. DRAM Contract Bidder Requirements

Ms. McMahon noted that the penalty provisions of the DRAM were set up to be comparable to the existing Aggregator Managed Portfolio (AMP) contracts. The Joint DR Parties disagree with the proposed penalty structure and suggest that the DRAM resource penalty structures should look like other RA resources. The Joint DR Parties are concerned that the DRAM proposal is event based whereas RA compliance looks at performance over a course of a period. In addition, the Joint DR Parties point out that the DRAM proposal does not factor in replacement obligations. TURN acknowledges the Joint DR Parties concern especially when the DRAM resource may only be called a few days a year.

DACC/AReM points out that the rules are in the CAISO tariff and that the CAISO can test the DRAM resource similar to a peaker plant. Comverge noted that in PJM's market, the DR provider is penalized for not showing up with the required registration and then is also responsible during the delivery year.

PG&E recommended workshops be conducted to determine the details of the DRAM auction and contracts.

6. Local DR and Local RA

As a result of prior workshop discussions, parties agreed that a discussion on Local DR and RA should occur. CLECA and PG&E posed questions for CAISO to clarify what the requirements are for Local RA. CAISO's Mr. Millar explained his testimony and that the CAISO expected Bifurcation to have predictable and reliable Load Modifying DR resources included in the CEC's forecast. The CAISO views the CEC as the lead in determining the resources to which the CAISO would need to be comfortable with the CEC's determination.

The CAISO explained that previously, there was plenty of traditional generation that local DR was unnecessary. However with the closure of the San Onofre Nuclear Generating Station (SONGS), in Summer 2012 the CAISO look at each DR program in Southern California to determine which ones met the CAISO requirements, e.g., the ability to dispatch within 30 minutes. The CAISO stated that none of the existing DR programs met the parameters they needed. When a transmission contingency occurs, they have to be able to reconfigure the transmission system within 30 minutes to be ready to meet the next contingency, if it were to occur. The CAISO is looking to a future where dispatch is fully automated for its requirements through its hoped-for Enhanced Contingency Modeling Initiative, to satisfy the N minus one minus one standard (N-1-1).

EDF expressed concern that the CASIO recognizes that Load Modifying DR has value but the CAISO does not give it value, thus treating Supply Resources as more valuable. The CAISO acknowledge that Load Modifying can reduce the need, but, to mitigate a transmission contingency, the CAISO has no visibility.

CAISO discussed how they are working to have a consistent method of accounting for the resources as ratified in the 2013 LTPP decision and they are working through the annual process to map the overlapping proceedings. Sierra Club noted CAISO's discounting of DR for local reliability in the LTPP Track 4 and that there is a need for a clear process for getting the resources to count. The Joint DR Parties noted that there is a gap between what was meeting RA but was not meeting Local and that having a moving target hurts DR.

CAISO responded that RA requirements would stay the same but a local area may need a longer requirement and noted that it is working with IOUs on procurement needs. The Sierra Club and Clean Coalition stated there is no visibility in resolving the requirements and there needs to be a stakeholder process.

I. Additional Issues/Considerations (June 11, afternoon)

1. Possible modification of CEC load forecasts to accurately account for load modifying demand response resources

PG&E described the history of accounting for DR that has not been bid into CAISO markets. Originally DR RA was taken off the top of the forecast of RA requirements. Subsequently, DR RA was part of the total of all RA resources used to meet RA requirements.

According to CEC representative, Chris Kavalee, the last time their demand forecast was developed, pricing DR program capacities were deducted from peak demand forecast projections. These programs included rate programs such as PG&E's SmartRate™ and Peak Time Rebate. The choice of DR programs to deduct from the forecast was based on CAISO input. The DR capacity value deducted was based on the utility-provided load impact protocol numbers. All event-based DR capacity gets added back into the actual loads when estimating baseline loads, then the event-based pricing programs are subtracted off of the peak load.

Concern was expressed about the amount of time it may take for new load modifying programs to be included in the calculations. CEC uses "uncommitted" DR for new programs and they are only included in the forecast once funded. CAISO expressed that any changes in the load modifying DR shows an impact in the RA requirement for the next year. RA reduction in year two, after the program has been implemented and used, is based on load impact protocols.

The parties disagree on the effect of not dispatching programs and its downstream effect on the load forecasts for DR and RA credits.

Non-event-based DR is part of the load history, but new non-event based DR can impact the forecast through the use of price elasticity.

2. Possible need for new protocols to address weather normalization of load-modifying DR

The parties discussed the best way to address weather normalization for new pricing programs. The concern is over pricing programs and if the first year of the programs, it is a cool year and the response is less than the actual capacity, will the response be weather adjusted? The question is whether there is any consideration or should there be any consideration to look at weather as an element of determining the actual DR capacity used in load forecasts.

CEC stated weather normalization of event-based load-modifying DR is done in the utility- provided annual load impact studies. The parties maintained there could still be an issue, though not clear if the issue is with all load-modifying DR or only non-event-based load-modifying DR. An example of this issue was offered by one of the parties: If you have a 100 MW resource on year 1, you can technically deduct 100 MW from your base. In year 2, your base line is 50 MW less (because only 50 of the 100 actually performed). Now your base load has a deduction of 50 built into it. Do you add the entire 100 for the next year, or do you only consider an incremental value of 50 MW? To the extent the load modifying DR is under counted, the utility is forced to buy added RA to cover RA requirements, creating a risk of double purchasing the RA required.

The ALJ suggested the parties resolve these issues by participating in the multi-agency discussion and working group (Demand Analysis Working Group or DAWG) dedicated to DR. CEC will provide the information about the next meeting to the service list.

3. Whether CAISO can rely on DR when repositioning after a contingency and its impact on DR value to meet Local RA requirements?

In the determination of local RA needs in LTPP, the CAISO did not count DR. If ratepayers are paying for DR, they want it to avoid generation.

The CAISO is required to reposition its resources within 30 minutes after the occurrence of a contingency event to prepare for the next one. After the SONGS closure, CAISO conducted a study of all the existing DR programs in the Southern California area and concluded that currently none of these programs met the current operation needs of CAISO. According to CAISO, DR resources are not considered when repositioning to prepare for the next potential contingency. The utilities provide a daily spreadsheet to the CAISO showing available DR resources per hour by the utility. Participants asked why can't the CAISO consider DR without being bid into the CAISO markets? CAISO maintains that its operators are not able to rely on spreadsheets in critical times such as repositioning to handle contingencies. If DR is bid in, the operators know about it. The CAISO is trying to better automate processes to handle resources (including supply-side DR) for operational needs through its Contingency Modeling Enhancements initiative, which is targeted for early 2015.

The parties discussed the CAISO procurement mechanism and whether CAISO accounts for the load modifying DR that a utility plans on dispatching on a day-ahead basis. CAISO maintains that the day ahead markets clear on the supply and demand bids so the demand bids reflect any day-ahead DR planned by utilities. The CAISO forecast process only impacts unit commitment after the integrated forward market. The real-time market reflects the demand that shows up.

If DR bids into the real-time market on an hour ahead basis, why doesn't it count for local RA? Why would DR with a 20 minute response not be a local resource? Other generation does not have that requirement. Long-start generation is called frequently if there is an expectation of need. The CAISO does not expect DR would be willing to be called frequently like other generation so DR, if it is only going to be called infrequently, it needs to be available for CAISO within 30 minutes to prepare for the next contingency.

Should the CAISO determine a system wide requirement for DR to count as local RA or a specific requirement for each local area? Local requirements for DR would vary widely by area depending on the expected occurrences and duration of conditions (mainly weather) that stress each local area.

With the retirement of SONGS, flow patterns changed, the N-1-1 analysis for transmission planning purposes changed. Before the SONGS closure, the contingency centered on transmission lines for fossil plants in the LA area. With the closure of SONGS, the CAISO's analysis revealed that the contingency shifted to center on the loss of two transmission lines to the San Diego area (the Southwest Power Link and the Sunrise Power Link.)

III.
CONCLUSION

The parties agreed the best way forward would be to create small working groups to talk about what can be settled. Parties noted that BUGS issues should be addressed in briefs and not a part of settlements. There was some discussion about separate working groups but the final decision was left to the parties. The parties agreed to inform ALJ Hymes by June 23 on the status of the settlement discussion and whether there is a need for further evidentiary hearings, which were tentatively set July 10 and 11, if needed.

On June 20, 2014, the parties reported to the ALJ verbally on their progress in the settlement discussion, and requested that the hearing dates of July 10 and 11 be vacated to allow the parties to concentrate their attention and resources on settlement efforts. The parties on the conference call requested that a new date be set around July 31, which would provide enough time to notice a settlement conference and file settlements that may be reached. This information was also presented in the status report filed June 23, 2014 in R.13-09-011.

Cost Allocation for IOUs' Demand Response Programs

June 9, 2014 CPUC Workshop
R.13-09-011

Proposed Commission Action

- Establish cost allocation principles in R.13-09-011 as proposed by DACC-AReM.
  - Ensures competitive neutrality and fairness in markets.
- Require IOUs to apply approved principles when requesting funding for any DR programs going forward.

Proposed Principles – Supply DR

- Characteristics of Supply DR:
  - Integrated with CAISO markets.
  - Treated like generation in those markets with the retail customer providing the resource to the market.
- Therefore, costs to be recovered like other market resources -- through generation rates.
- All benefits (RA) to be retained by bundled customers.

Proposed Principles – Load-Modifying DR

- Characteristics of Load-Modifying DR:
  - Reshapes or reduces net load curve.
  - Retail customer provides the resource, which is used as substitute for other generation to meet LSE's RA requirements or to shift peak load, if approved for that purpose by the CPUC.
  - Also includes pricing tariffs solely applicable and available to bundled customers, which are used to reshape or reduce IOU's net load curve.
- Therefore, costs to be recovered as follows:
  - Programs that are open to all customers, but function as substitute for generation, are to be recovered the same as other similar resources – through generation rates.
  - Programs solely applicable and available to bundled customers are to be recovered solely from those bundled customers. (See, D.12-12-004).
  - All benefits, load reduction and RA, from these programs are to be retained by bundled customers.

Adverse Effects of Current Cost Allocation

- Current cost allocation is primarily through distribution rates, which:
  - Depresses generation rates artificially, thereby giving IOUs a competitive advantage; conflicts with CPUC Unbundling Decision (D.97-08-056).
  - Creates inappropriate cross-subsidies.
  - Conflicts with CPUC policy of competitive neutrality.
  - Discourages third-party entry into DR market.

Reason to Decide Now

- Identified as "foundational issue" in Scoping Memo that requires resolution.
- D.12-04-045 directed that cost allocation be:
  - Considered in the successor policy proceeding to R.07-01-041 *and*
  - Decided in a "consistent manner across all three utilities."
- Foundational to ensuring competitive neutrality and fairness in markets.
- Uniform cost allocation principles should be established for DR and applied consistently across the 3 IOUs to address current inequities.

Overview of CAISO Integration Costs for PG&E

Corey Mayers
PG&E's Demand Response Department
Customer Energy Solutions

Order of Presentation Topics

1. How PG&E disaggregated Rule 24 functions to help break out its costs

2. What Rule 24 functionality already exists

3. Rule 24 related costs in current proceedings

4. What activities are supported by these costs

5. Summary of total CAISO integration costs

6. Key take-aways

Cost Incrementality

- Costs provided are INCREMENTAL to current or previously funded processes and IT work.

- **PG&E has requested cost recovery for its MRTU work but has yet to receive cost recovery for that work.**

How PG&E Disaggregates Rule 24 Functions When Deriving its Costs in These Proceedings.

This matrix will be used to describe the scope of all cost recovery filings to follow And Services

Case	**Customer**	**LSE**	**MDMA**	**DRP**
1	Bundled	PG&E	PG&E	PG&E
2	Bundled	PG&E	PG&E	3rd party
3	CCA	3rd party	PG&E	PG&E
4	DA	3rd party	PG&E	PG&E
5	CCA	3rd party	PG&E	3rd party
6	DA	3rd party	PG&E	3rd party
7	DA	3rd party	3rd party	PG&E
8	DA	3rd party	3rd party	3rd party

All Combinations of PG&E Roles and Customer Types **Plus**

All Combinations of ISO Product Offerings

MRTU Proceeding

MRTU Foundational Work
PG&E bids in PDR for one of its programs ("PDR1")

Most Simple Case

					Supported Day Ahead Products			Supported Real Time Products	
Case	Customer	LSE	MDMA	DRP	Energy	A/S	RUC	Energy	A/S
1	Bundled	PG&E	PG&E	PG&E	YES	NO	NO	NO	NO

Used for Peak Choice Program in 2011 and 2012

Rule 24 Cost Recovery Application filed June 2nd, 2014

Cost to Fully Integrate Third Party Bidding into CAISO Market

As Illustrated in Appendix B of Application

Rule 24 Cost Recovery Filing – Appendix B Full Implementation <u>for non-Utility DRPs</u>

					Supported Day Ahead Products			Supported Real Time Products	
Case	Customer	LSE	MDMA	DRP	Energy	A/S	RUC	Energy	A/S
1	Foundational Work – Partially Implemented, Updated with PDR2								
2	Bundled	PG&E	PG&E	3rd Party	YES	YES	YES ?	YES	YES
3									
4									
5	CCA	3rd party	PG&E	3rd Party	YES	YES	YES?	YES	YES
6	DA	3rd party	PG&E	3rd Party	YES	YES	YES?	YES	YES
7									
8	DA	3rd party	3rd party	3rd Party	YES	YES	YES?	YES	YES

Cost estimate for 3rd party full implementation is about $19M

Business and IT Activities Needed to Facilitate non-IOU DRPs Participation into CAISO Market

Activity Number	Activity Description
1	Isolating PG&E staff that provide services to non-utility DRPs
2	Establishing and maintaining third parties as non-utility DRPs
3	Processing and maintaining a DRP's Access to customer specific data via CISR-DRP Form
4	Modifying PG&E systems to produce and track non-interval data needed for Rule 24
5	Transferring interval data on an ongoing basis to DRPs
6	Transferring non-interval data on an ongoing basis to DRPs
7	Reviewing CAISO registrations
8	Preventing dual enrollment by customer in utility DR programs and non-utility DRPs
9	Forecasting load reductions for PG&E Bundled customers
10	Manage Energy Procurement and Settlements

IT Only Functions

Rule 24 Cost Recovery Application filed June 2nd, 2014

PG&E's *Reduced* Rule 24 Cost Recovery Request

As Illustrated in PG&E's Testimony

Rule 24 Cost Recovery Filing –

PG&E's *Reduced* Cost Recovery Request

Limited Scope	2014	2015	2016
Maximum Non-Residential Customers:	20	100	500
Maximum Electric Meters:	30	150	750
Maximum Number of DRPs:	2	5	5
Maximum Wholesale Resources (PG&E as LSE):	6	6	6
Maximum Load Reduction (PG&E as LSE):	50 MW	50 MW	50 MW
Residential Participants Allowed:	N	N	N

2013 Demand Response OIR, Phase 2 and 3
Filed May 6, 2014

Full Implementation for PG&E as the DRP – Current DR Programs (“PDR2”)

					Supported Day Ahead Products			Supported Real Time Products	
Case	Customer	LSE	MDMA	DRP	Energy	A/S	RUC	Energy	A/S
1	**Programs TBD**	PG&E	PG&E	PG&E	YES	YES	YES?	YES	YES
2	Provided under Rule 24 Cost Recovery Application								
3	CCA	3rd party	PG&E	PG&E	YES	YES	YES?	YES	YES
4	DA	3rd party	PG&E	PG&E	YES	YES	YES?	YES	YES
5	Provided under Rule 24 Cost Recovery Application								
6									
7	DA	3rd party	3rd party	PG&E	YES	YES	YES?	YES	YES
8	Provided under Rule 24 Cost Recovery Application								

IT Activities to Needed to Facilitate PG&E Bidding it DR Programs into CAISO Market

Convert Programs for PDR Day Ahead Energy

- SmartAC™ Program
- Capacity Bid Program (CBP)
- Aggregator Managed Portfolio (AMP)

Expand PDR platform to enable Real Time Energy

- Convert SmartAC Program

Convert BIP for RDRR Real Time Energy

Expand PDR platform to enable ancillary services (excludes telemetry)

Summary of Costs to FULLY Integrate into CAISO Markets

1. MRTU Proceeding (incremental already incurred) ...$ 16M
2. Rule 24 Cost Recovery (incremental). ....$ 19M
3. 2013 DR OIR (incremental)..........................$ 19M-$30M

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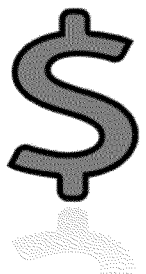
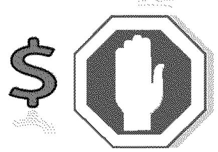
Total Cost .... $ 54M - $65M

PG&E's Incremental Costs .... $ 38M - $49M

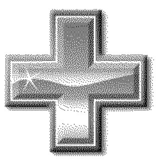
Key Take-Aways



- It is expensive to fully integrate retail DR into the CAISO market



- It is less expensive to manually integrate DR reductions into the market – but it has limits



- The costs of integration are incremental

- Given the costs and market uncertainties, (FERC 745) it may be prudent to wade into the pool rather than to dive right in.


THANK YOU

Witness Present for Questions

- Steve De Backer – Processes
- Stephen Kung – IT Costs

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CAISO Market DR Integration Costs

Demand Response OIR Workshop

David Lowrey / Muir Davis

June 9, 2014

SCE's CAISO Market Integration Costs

- $5.8 million **requested** in 2015 GRC Phase 1 (A.13-11-003)
  - Define Proxy Demand Resources (PDR) and Reliability DR Resources (RDRR) to represent SCE's DR programs and customers in different geographic areas
  - Forecast MW capacity of SCE's DR resources
  - Develop and submit bids for each SCE DR resource
  - Retrieve awards from CAISO for DR resources and translate the awards into the event instructions for the retail DR participants
  - Monitor performance of DR resources
  - Perform wholesale settlements
- $5 million **authorized** in 2012-14 DR Funding Cycle (D.12-04-045)
  - Modification of SCE's DR programs for participation in CAISO markets
  - Mapping of customer / account to system location
- June 2 Rule 24 Cost Recovery Application did not request incremental cost recovery (proposed to use D.12-04-045 to cover $2.7M in costs)

SDG&E Electric Rule 32 Implementation Costs

SDGE connected
A Sempra Energy utility

June 9, 2014

SDG&E programs integration

SDGE connected
A Sempra Energy utility™

- Dependent on outcome of bifurcation proceedings
  - Program classification
- Complexity of integration
  - Manual processes
    - Portions of Capacity Bidding Program
  - Automation
    - Summer Saver

Third party enablement

SDGE connected
A Sempra Energy utility℠

- IT upgrades needed regardless of level of participation
- Core SDG&E system upgrades:
  - CRM
  - CISCO (Billing)
  - Information Security
- Middleware infrastructure enhancements
  - Real time, batch, one-way and bi-directional interfaces
- Cost:
  - $1.5-$3 MM
- Business process cost
  - $600k- $750K

Timeline

2014

- Partial CBP integration
- DR OIR decisions
- Cost recovery application

2015

- CBP, BIP integration
- Potential 3rd party participation

2016

- Supply resource integration
- 3rd Party Participation

JDP's Cost of Integration Presentation

June 9, 2014

Agenda

- Categories of DRP Integration Costs
- CAISO Metering and Communications Requirements
- Metering and Communications Requirements of Other ISOs/RTOs
- Why These Requirements Add Costs/Risk
- Local Dispatches

Categories of Wholesale Market Integration Costs

- Connecting to CAISO's systems to submit bids, communicating metering information, etc.
- Becoming or retaining a scheduling coordinator
- Software costs-including programming and testing of logic to comply with the program design and rules. (4-6 man-months)
- Hardware costs to provide curtailment
- Personnel costs
- Operations systems design (one-time cost, with maintenance as required for changes/updates)
- Metering costs
- Customer engagement costs

Description of CAISO Metering Requirements for PDR and RDRR

Source: CAISO Metering BPM

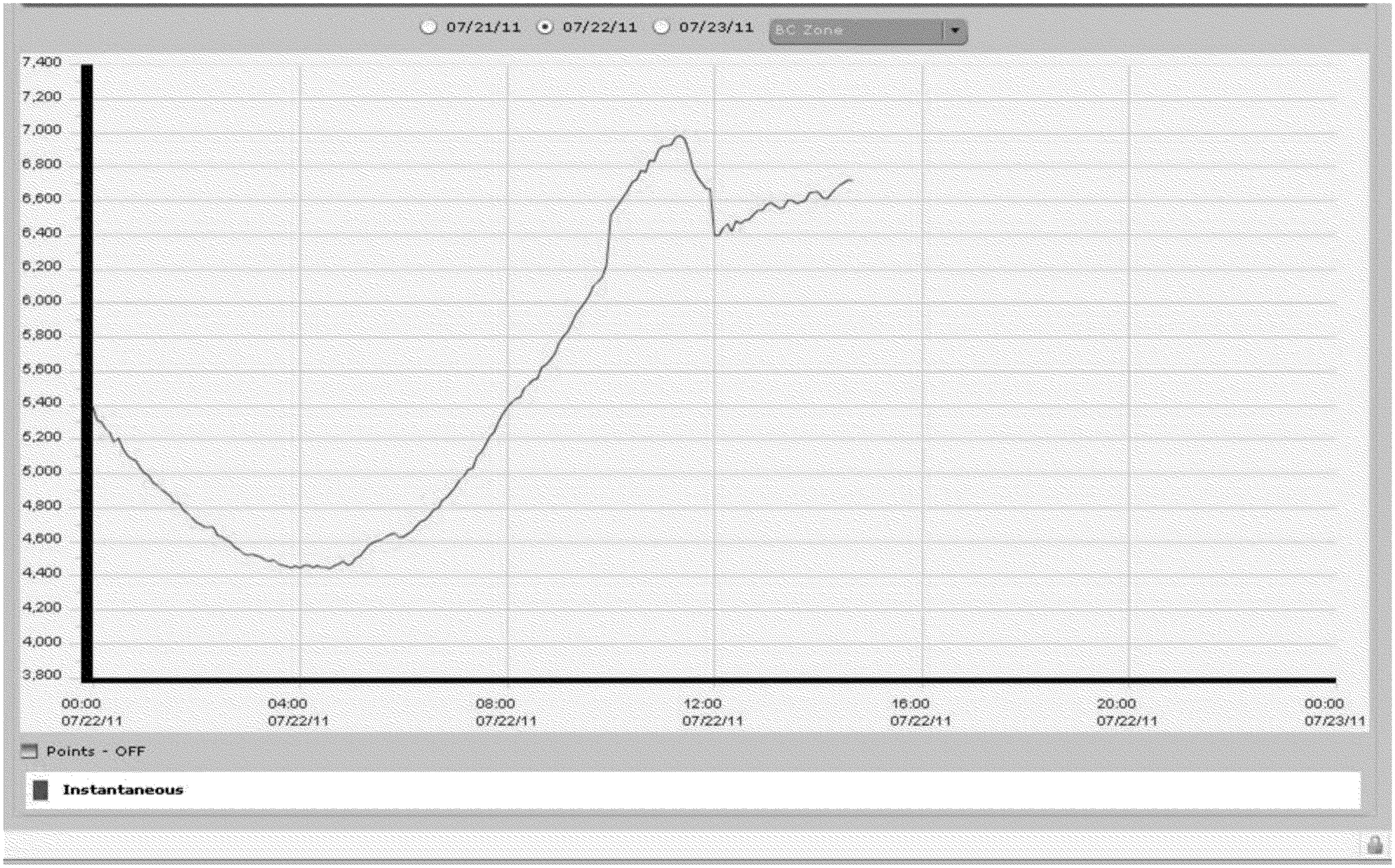
- General Requirement for Telemetry:
  - Resources with a capacity of 10 MW or greater (at the resource level)
  - Resources that provides ancillary services
  - Eligible intermittent resources
- Participating Load and PDR are subject to these requirements
- Telemetry is not required for RDRR
- Remote Intelligence Gateway (RIG) must be present in the sub-LAP where resources reside. This is waived for PDR.
  - Means that a central "RIG" can be used for PDR resources
- All telemetry data must be within +/- 2% of the true value
- Dedicated T1 circuit, backup and a diversely routed T1 circuit
- Requires 1 minute interval data be transmitted
- Maximum of 25 resource IDs may be associated with a single RIG

Comparison of CAISO Metering Requirements to Other Markets

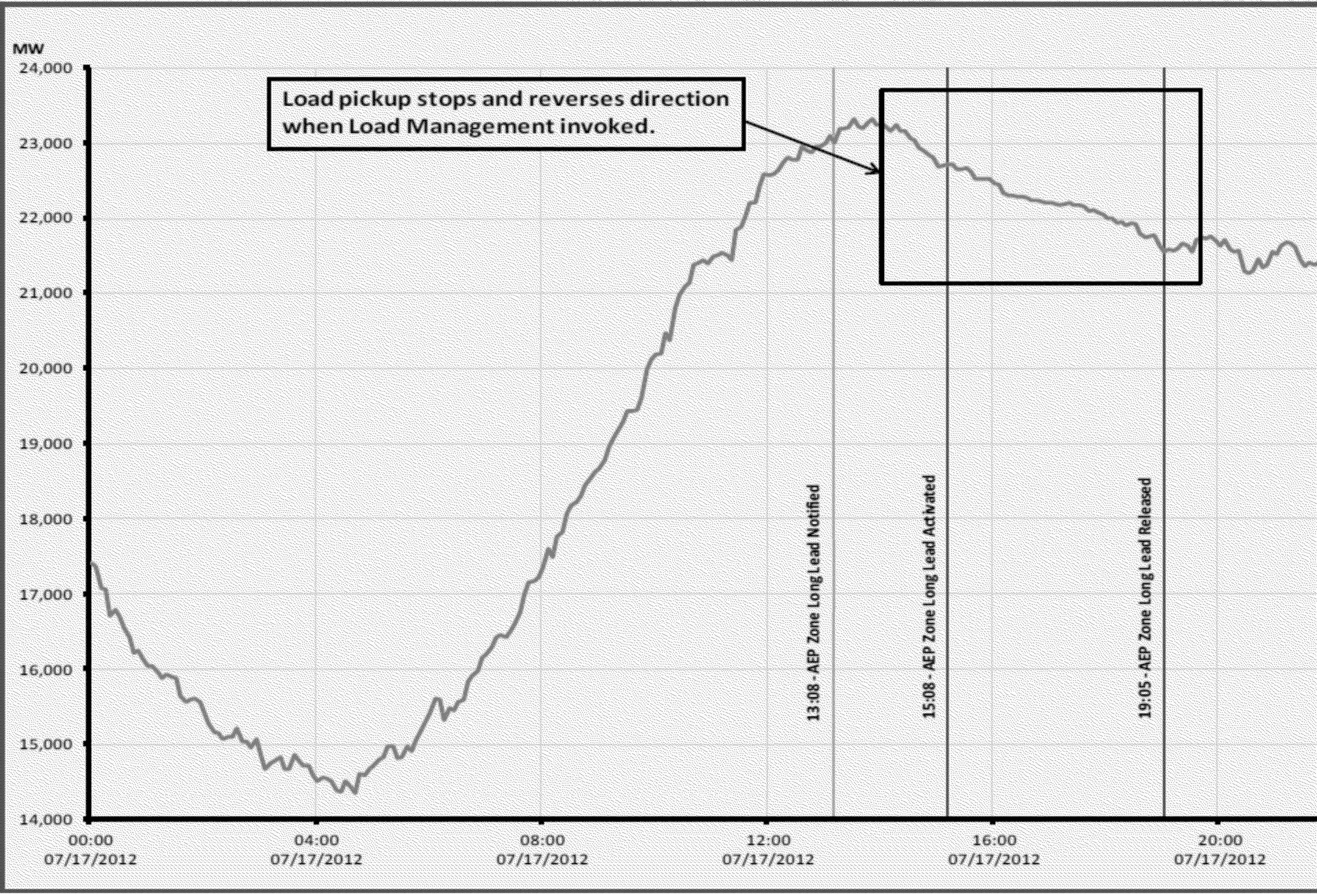
It is unclear why CAISO's requirements need to surpass those employed by other markets.

- PJM
  - No requirement for near, real-time operational data
  - Hourly interval data for energy
  - 1 minute data required for 10-minute and 30-minute reserves, reported within 2 business days
  - Telemetry required for frequency/regulation resources
  - Settlement data for energy required 60 days after dispatch
  - PJM monitors load buses in real time
- MISO
  - No telemetry requirement for energy or A/S
  - Hourly interval data for energy
  - 5-minute interval data for spinning or non-spinning reserves submitted 5 days after dispatch.
  - Telemetry required for regulation only
  - Data reported 5 days after dispatch

PJM Screen Shot for BGE Zone



Instantaneous AEP Zonal Load 7/1



Why Do CAISO's Requirements Add Cost/Risk?

- Telemetry requirement can be avoided by reducing aggregation size below 10 MW; but, there are costs/risks associated with reducing the portfolio size:
  - Increases performance risk by reducing aggregation size and portfolio diversity
  - Increases administration by DRP by increasing number of resources that require management
  - Decreases customer pool from which participants will be accepted into the portfolio
  - May run afoul of internal risk management guidance
- DRP could use NOC to provide operational data by resource to CAISO
  - Must meet communications requirements (Olivine's DER Integration Report, January 6, 2014, at pp. 22-23.)
  - DRPs are not collecting 1 minute data for energy deliveries currently
  - Incurs risk for accuracy of operational data (+/- 2% of true value), despite the fact that DRP does not receive RQMD from LSE's MDMA until T+33 days
  - DRP would have to limit resource registrations from NOC to 25

Sub-LAP Bidding and Settlement

- CAISO's tariff requires DR resources to be bid, scheduled and settled on a sub-LAP basis.
- Other markets allow for a resource to be dispatched as broadly as on a system-wide basis or down to a local area depending upon system needs.
  - PJM, ISO-NE, ERCOT, NYISO do not require local dispatch at all times
- CAISO's current construct does not permit DR to act as a system resource, even if a requirement is developed on a system-wide basis (FRACMOO).
- While JDP's are technically capable of delivering on a local basis, sub-LAP dispatches are more difficult to administer and are more costly, including performance risk, than resources that serve larger geographical areas.
- Sub-LAP portfolios require more customer engagement activity and costs.
- If multiple sub-LAPs are dispatched, allow for settlement across dispatched sub-LAPs.

Recommendations

- DRPs will evaluate costs of participating in CAISO markets relative to the revenue opportunity and determine if it is a cost-effective proposition.
- DRPs will evaluate the CAISO market opportunity relative to other markets and make rational decisions as to how best to allocate resources.
- Customers will have to decide if participation in DR provides a value proposition for them with increased communications costs.
- Exempt DR resources from telemetry requirement
  - It adds unnecessary costs and risks.
  - Allow for reporting of estimated data by T+5 business days.
  - It is a requirement in excess of those required by other markets that have successfully integrated DR.
- Allow resources to submit bids and settle over larger geographic areas than a Sub-LAP (System, DLAP, and LCA) and allow settlement across dispatched sub-LAPs.
- Use sub-LAP dispatches only when local dispatch is required, not as a rule of thumb.

Summary of Demand Response Providers Operating in Other ISOs
and Key Market Characteristics

	Market/ISO			
	PJM	**ERCOT**	**NY ISO**	**ISO NE**
DR Providers Registered	80	19	41	8
Utilities listed as DR Provider	8	-	8	1
Net Non-Utility Providers	72	19	33	7
Capacity Market	Yes	No	Yes	Yes
Customer Procurement	Procure capacity obligation, then aquire customer (three year window)	Acquire customer, then bid for capacity obligation (obligation begins in weeks)	Procure capacity obligation, then acquire customer (one year or shorter window)	Procure capacity obligation, then acquire customer (three year window)
Dispatch Notice	30, 60, or 120 Minute	10 or 30 minute	Day ahead **and** two hours prior to event	30 minute
Metering Requirement	Hourly	Utility Meter (AMI fully deployed)	Hourly	5 minute meter, RT communications with ISO