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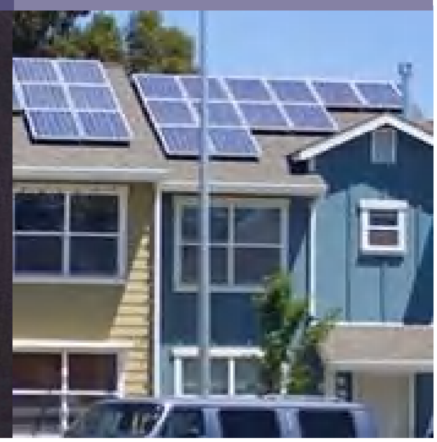
# California Independent System Operator Demand Response Barriers Study (per FERC Order 719)

**April 28, 2009**



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# EXECUTIVE SUMMARY

This report summarizes the findings of California ISO's (CAISO's) study of demand response (DR) barriers conducted in response to Federal Energy Regulatory Commission (Commission) Order 719. The study was commissioned and directed by the CAISO and completed by the consulting team of Freeman, Sullivan & Co. (FSC) along with Energy and Environmental Economics, Inc. (E3).

The study was structured to respond directly to FERC Order 719 paragraphs 274-276. To comply with the Order, the consultant team defined the scope to:

- include all barriers to demand response from the perspectives of a broad range of DR stakeholders including those with minority perspectives;
- prioritize the barriers in consultation with the CAISO and the goals established by the Commission; and
- develop timelines for addressing each barrier.

In addition, the study was narrowed to focus explicitly on the California market. Although there may be common DR barriers across restructured markets, the study focuses on California alone and does not attempt to draw comparisons.

## Stakeholder Process

In order to elicit opinions on the barriers to demand response (DR) in California from a broad range of stakeholders, the consultant team led a directed process of interviews and outreach, and conducted a public webinar as a forum to receive feedback from all interested parties. To initiate the process, the consultants developed an interview questionnaire based on discussions with the CAISO staff, their own experience and a literature review; the bibliography is included in Appendix A. Based on the information gathered through this research, the consultant team drafted an initial set of DR barriers which formed the basis for the CAISO hosted webinar.

Overall, participation in the process was robust. The consulting team held interviews with 13 entities involving 30 staff overall. Those interviewed included investor-owned utilities, regulatory entities, demand response/Curtailment Service Providers (CSPs), consumer advocates, customer representatives, and Energy Service Provider (ESP) representatives. Following the interviews, approximately 50 stakeholders participated in the webinar. Comments on the materials presented at the webinar were received from 9 organizations and were considered in the development of the final report.

## Prioritized Barriers and Solutions

Following the feedback gained from the webinar, the consulting team prioritized the barriers identified through the research, interviews, and the stakeholder feedback. First, the complete list of barriers was divided between 'barriers' and 'critical issues.' DR 'barriers' continue to be viewed as more significant challenges, typically resulting from a policy conflict that must be resolved in order to eliminate the barrier. DR 'critical issues' were challenges judged as being significant but possibly resolvable over time through the existing processes underway in California. Webinar participants were asked for their categorization between barriers and issues, which the CAISO and consulting team considered in making a final determination on the distinction.

Secondly, the barriers were subjectively prioritized into high, medium and low categories by the consulting team and the CAISO using two criterion. The first criterion is the degree to which the barrier was viewed as inhibiting comparable treatment of generation and DR resources. The resource comparability criterion is taken directly from the Commission's ruling in Order 719. The second criterion was the degree to which the barrier was viewed as inhibiting the pursuit of increased participation of demand response in CAISO markets.

The following tables provide a summary description of each of the barriers and critical issues identified by category, its priority, and a summary of the proposed solution. The five categories used to organize the barriers include market, regulatory, customer, technology and infrastructure, as well as operations and settlement.

**Table 1: Market Barriers and Critical Issues**

| Barrier | | Priority<br>CAISO Role | Solution |
|---|---|---|---|
| **MB.1** | **Resource Adequacy (RA) Capacity payments are elusive for DR resources directly participating in the CAISO markets outside of a retail DR program** | High<br>Advocate | CAISO actively participate in current and future CPUC DR and RA proceedings to ensure greater alignment and comparability between retail and wholesale DR revenue streams. |
| **MB.2** | **Lack of a transparent, forward capacity market for direct participation DR resources** | High<br>Advocate | Continue to engage stakeholders and the CPUC in the Long Term RA proceeding (R.05-12-013) to determine the appropriate mechanism for clearing RA capacity. Work with stakeholders and CPUC to address how DR resources can access RA capacity payments. |
| **MB.3** | **WECC standards preclude DR resources from participating in regulation and spinning reserve markets** | High<br>Direct | CAISO will launch an initiative to evaluate the ability to revise definitions of existing AS products to ensure technology neutrality, seeking FERC approval and WECC alignment. |
| **MB.4** | **Customers accustomed to existing investor-owned utility programs** | Low<br>Limited | Continue engagement with stakeholders to develop viable wholesale DR products with direct participation capability. Work with stakeholders and the CPUC on greater alignment between retail programs and wholesale products. |

**Table 1: Market Barriers and Critical Issues cont'd.**

| Critical Issue | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **MI.1** | Attributes of existing programs poorly aligned with CAISO markets | High / Advocate/ Direct | Pursue greater alignment through CPUC DR OIR (CPUC R.07-01-041), and other relevant CPUC proceedings, CAISO stakeholder process and CAISO market and product design efforts. |
| **MI.2** | CSPs[1] precluded from direct participation without FERC approval of the PDR product | High / Direct | Continue PDR stakeholder process targeting May 2010 implementation. Stakeholder support in the design and approval of wholesale DR products. |
| **MI.3** | IOUs will likely remain a key player in offering DR to retail customers, and will take direction from the CPUC and CEC, not CAISO | Medium / Advocate | CAISO will continue to participate in CPUC DR and other relevant proceedings with goal of increasing alignment of utility programs and facilitating direct participation of DR resources. |
| **MI.4** | Various DR Market Vision perspectives among stakeholders | Medium / Inform | Promote understanding of CAISO policy and positions through participation in relevant CPUC proceedings. |

**Table 2: Regulatory Barriers and Critical Issues**

| Barrier | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **RB.1** | **Fundamental policy differences between the wholesale (FERC/WECC/CAISO) and retail (State Legislature/CPUC/CEC) perspectives** | High / Policy Reconciliation | Pursue greater alignment through CPUC DR OIR (CPUC R.07-01-041), and CAISO stakeholder process. |
| **RB.2** | **Regulatory driven retail programs limit growth opportunity for CSPs** | Medium / Limited | Work with CPUC and stakeholders to ensure better alignment between retail and wholesale DR programs. Continue to develop and refine the direct participation capability of DR resources, including the ability to access RA and A/S capacity payments. |

[1] For the sake of simplicity, the term Curtailment Service Provider or "CSP" will be used to refer to any non-utility DR provider, although utilities do sometimes refer to themselves as a CSP with respect to the direct participation of utility managed DR programs. It may also be possible for ESPs to act in the role of a CSP for DA customers.

**Table 2: Regulatory Barriers and Critical Issues cont'd.**

| Critical Issue | | Priority<br>CAISO Role | Solution |
|---|---|---|---|
| **RI.1** | Program value may not be fully recovered in wholesale market, limiting incentives for direct participation | High<br>Policy Reconciliation | Continued CAISO engagement in the CPUC DR OIR- Cost-effectiveness proceeding (CPUC R.07-01-041) as well as informing interested parties about the plethora of performance reporting processes conducted and published by the CAISO. Such reports, especially with MRTU market data incorporated, should help better inform this issue over time. |
| **RI.2** | Political resistance to reflecting dynamic or locational pricing in retail rates | Low<br>Inform | CAISO products such as PDR (if approved) and Participating Load enable demand response providers to earn the locational marginal price for load curtailments. The CAISO's market produces and publishes locational marginal prices, reflecting the cost of consuming energy at specific times and places on the grid. The CAISO's market design establishes a solid foundation for the CPUC to consider incorporating dynamic or locational pricing into retail rates. |
| **RI.3** | Mixed signals from 5% DR goal, Integrated Energy Policy Report (IEPR) loading order and cost-effectiveness protocols | Low<br>Policy Reconciliation | Remain engaged in CPUC DR OIR (CPUC R.08-06-001) and follow Long Term Procurement Proceeding (CPUC R.08-02-007); this is a longer-term barrier that is engrained in and integral to the state's long-term procurement policies. |
| **RI.4** | Multiple initiatives overwhelming capacity of stakeholders and market participants | Low<br>Participant | Promote initiatives through and utilization of the "Market Initiatives Roadmap" |

**Table 3: Customer Barriers and Critical Issues**

| Barrier | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **CB.1** | **Complexity of the DR market offerings from a customer's perspective** | Low<br>Direct | CAISO to develop and offer a structured bid-to-bill DR training program for market participants |

| Critical Issue | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **CI.1** | Utilities, Regulators and CAISO underestimate the challenge of changing customer behavior | High<br>Direct/Policy Reconciliation | Continue targeted pilot projects to inform the overall DR development process and overcome technical and integration issues. Continue reliance on stakeholders involvement in the development of viable and attractive DR products |
| **CI.2** | Based upon historical DR involvement, CAISO market requirements are likely ill suited for many customers' pursuing direct participation | Medium<br>Direct | CAISO Participating Load pilot projects will inform and provide lessons learned and seek better, easier to implement, more cost-effective alternatives to integrating DR resources in CAISO markets. |

**Table 4: Technology and Infrastructure Barriers and Critical Issues**

| Barrier | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **TB.1** | **Infrastructure and systems requirements and costs associated DR under MRTU** | Medium<br>Inform | Develop and provide market participants with clear specifications about system and business requirements. Current activities and forums are helping to elicit these requirements include the Participating Load pilot projects, CAISO Business Issues and Processes working groups, and on-going/evolving CPUC policy on how "locational" it wants to make DR as a resource or as a dynamic rate. |

**Table 5: Technology and Infrastructure Barriers and Critical Issues cont'd.**

| Critical Issue | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **TI.1** | Scheduling Coordinator/Transmission level requirements for participating load | Low / Direct | Engage and walk CSPs through the CAISO's SC Application Process. CAISO provides single point of contact for any entity interested in becoming an SC. Documentation is published and available on how to become a SC with overview materials.[2] |
| **TI.2** | Limitations of AMI | Low / Participate | Address through CAISO Business Issues and Processes working groups; tighter coordination/ communication between CAISO and utility AMI and DR staff |

**Table 6: Operations and Settlement Barriers and Critical Issues**

| Critical Issues | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **OI.1** | Inherent compromises in balancing multiple objectives of baseline methodology | High / Direct | CAISO Business Issues and Processes working group plans to address this issue early and sees it as highest priority. |
| **OI.2** | Complexity of scheduling and settlement | Medium / Direct | CAISO to develop and offer a structured bid-to-bill DR training program for market participants. |
| **OI.3** | Potential for gaming due to differences between nodal and aggregated prices | Low / Direct | Gaming opportunities viewed as limited in nature; will be handled through market monitoring and specific market design elements targeted to address specific potential gaming concerns. |

## Initiatives and Timelines

To address the barriers that have been identified, the CAISO plans to continue its own efforts and stakeholder processes and engage in other DR processes at the CPUC, WECC / NERC, and the Commission. The Commission's Order 719 requests a timeline for addressing each barrier, and timelines have been developed for all processes. The initiatives managed by the CAISO have more certainty since the CAISO sets the respective schedule.

Implementation of New and Refined DR Products (May 2010).
**Participating Load Program Refinements**: The CAISO transitioned its existing Participating Load Program into the MRTU environment on March 31, 2009; however, the full Participating Load functionality originally approved by FERC and intended for the

[2] http://www.caiso.com/docs/2005/10/05/2005100520241822328.html

initial release of MRTU was delayed and, as an interim measure, MRTU was supplemented with more limited functionality. The CAISO plans to implement the intended refinements to its Participating Load Program by May 2010. These refinements will make Participating Load a unique resource that can participate in the ancillary service markets and be co-optimized for energy and ancillary services.

**Proxy Demand Resource**: Through the stakeholder and working group process, the CAISO and its stakeholders developed the proposed Proxy Demand Resource (PDR) product. The proposed PDR product would resolve certain barriers to DR participation in the CAISO markets and enable load-serving entities (LSEs) and CSPs to directly participate by providing demand response resources via retail demand response programs in the CAISO markets. The proposed PDR product will help address concerns that were raised, such as;

- **MI.2** CSPs precluded from direct participation without FERC approval of the PDR product
- **RB.2** Regulatory driven programs limit growth opportunity for CSPs

<u>Comparability Request for DR at WECC (Fall 2009</u>**)**. The CAISO plans to a file a SAR (standard authorization request) with the WECC, asking it to create a standards drafting team to rewrite WECC standards for regulation and spinning reserves in order to allow non-generation resources to provide these services. The CAISO also plans to develop, independently, a set of standards that WECC may or may not adopt, but which the ISO will ultimately file with FERC as proposed revisions to its tariff. The initial workshop to discuss these revisions will be held on June 16. This will be followed by a series of technical workshops and stakeholder calls with the ultimate goal of finalizing proposals in the fall of 2009 for presentation to the CAISO Board of Governors before year-end. The results should address the following barriers:

- **MB.3** WECC standards preclude DR resources from participating in regulation and spinning reserve markets

<u>CAISO Participating Load pilot projects (Expected completion- Phase 1: December 2009)</u>. The CAISO is in the process of developing three participating load pilot projects that will be operational by the summer 2009 with the goal of providing non-spinning reserves from a cross-section of end-use load types. SDG&E will demonstrate a commercial aggregation project with end users whose load consumption is greater than 20 kW. SCE will demonstrate an aggregation of 3,200 residential AC cycling units and PG&E will conduct a test involving large commercial and industrial customers. The objectives are to understand the performance and reliability attributes of different participating load resource types, explore telemetry requirements and alternatives, identify and address operational issues, and build confidence around non-generation resources providing a high quality reliability service.

The pilot projects will help the CAISO with resolution of several barriers identified with integrating and increasing participation of DR resources, including:

- **TB.1** Infrastructure and systems requirements and costs associated DR under MRTU
- **CI.2** Based upon historical DR involvement, CAISO market requirements are likely ill suited for many customers' pursuing direct participation

Identification and Resolution of Direct Participation Business Issues (April-August 2009)
The CAISO is launching a structured working group process to discuss and resolve the issues around the direct participation of demand response participating under the proposed PDR product in the CAISO markets. The business issue resolution process will focus on the following seven categories:

- **Qualification**: program definition, participant and resource qualification)
- **Registration:** resource characteristics, enrollment, transfers, testing and auditing)
- **Scheduling:** system and resource forecasting, resource scheduling and bidding)
- **Notifications:** market schedules and awards, RT dispatch, outages)
- **Metering and telemetry:** data availability, exchange, type and granularity)
- **Settlement:** calculation of load changes, calculation of credits and charges)
- **Performance and compliance evaluation**:[3] resource, participant, program, and system performance evaluation, compliance monitoring

Additional details about this business issues resolution framework can be found in Appendix F.

CPUC DR OIR (CPUC R.07-01-041) (Ongoing- Initiated January 2007**).** These proceedings are working on refining the existing set of CPUC authorized DR programs at the California IOUs (PG&E, SCE, and SDG&E). Within the scope of the DR OIR is better integration of DR with the CAISO markets. The CAISO has been an active participant in these proceedings, and looks forward to working with the CPUC to achieve this goal. The DR OIR is the primary pathway to address the following barriers and critical issues over the next year or two:

**MB.1** Resource Adequacy (RA) Capacity payments are elusive for DR resources directly participating in the CAISO markets outside of a retail DR program
**RB.1** Fundamental policy differences between the wholesale (FERC/WECC/CAISO) and retail (State Legislature/CPUC/CEC) perspectives
**MI.1** Attributes of existing programs poorly aligned with CAISO markets
**CI.6** Program value may not be fully recovered in wholesale market, limiting incentives for direct participation

CPUC Resource Adequacy (RA) proceeding (CPUC R.05-12-013 & R.08-01-025) (Ongoing- Initiated December 2005, current proceeding initiated January 2008). CAISO will continue to engage in the CPUC's RA proceedings. For CPUC jurisdictional entities, satisfying the CPUC's Resource Adequacy requirements ensures sufficient capacity is installed and available to satisfy the system-level Planning Reserve Margin and the CAISO's local capacity area needs. Resource Adequacy capacity is either self-supplied through retained generation or procured through bilateral arrangements whereas dispatchable demand response resources, under the CPUC RA rules, is deemed as RA-

[3] CAISO Demand Response Strategic Initiative Program Overview Presentation. February 16, 2009.

qualifying capacity, granted minimum resource availability requirements are satisfied.[4] Qualifying capacity associated with retail DR programs is allocated by the CPUC to its jurisdictional entities with the allocated portion helping to satisfy the CPUC jurisdictional Load Serving Entity's RA requirement.

CAISO will continue to be an active participant in the CPUC's RA proceedings[5] and continues to support comparable treatment across resource types. Additionally, CAISO has been a proponent of a centralized capacity market and is hoping this topic is reinitiated at the CPUC.[6] CAISO participation in the CPUC RA proceeding has the potential to help address the following barriers:

- **MB.1** Resource Adequacy (RA) Capacity payments are elusive for DR resources directly participating in the CAISO markets outside of a retail DR program
- **MB.2** Lack of a transparent, forward capacity market for direct participation DR resources

<u>CPUC Smart Grid Proceeding (R. 08-12-009) (Ongoing- Initiated December 2008)</u>. In December 2008, the CPUC initiated its Smart Grid Rulemaking Proceeding. The proceeding will investigate how to enhance the ability of the electric grid to support policy goals including reducing greenhouse gas emissions, increasing energy efficiency and demand response, expanding the use of renewable energy, and improving reliability. Based on its findings, the CPUC will set policies, standards and protocols to guide the development of a smart grid system and facilitate integration of new technologies such as distributed generation, storage, demand-side technologies, and electric vehicles. The Pre-Hearing Conference initiating workshops and hearings was held March, 27 2009. A proposed schedule for the proceeding has not yet been announced.

This has the potential to address these barriers:

- **B.8** Infrastructure and systems requirements and costs associated DR under MRTU
- **CI.12** Limitations of AMI

[4] See CPUC D.05-10-042 pp. 51-54

[5] Including, but not limited to, R.05-10-042, R.08-01-025, R.05-12-013, et al.

[6] The CAISO has supported the centralized capacity market concept proffered by the California Forward Capacity Market Advocates (CFCMA) and has stated that the CFCMA proposal "offers a solid basis for developing an effective central capacity market design. It will provide transparent prices and needed price signals for investment decisions and economic trade-offs among investments in new generation, demand response and transmission." See page 2 in the CAISO's Reply Comments of The California Independent System Operator to Comments on Staff's Modified Centralized Market Proposal, R.05-12-013, December 15, 2005 found at: http://www.caiso.com/205b/205b87ea72510.pdf

# TABLE OF CONTENTS

# List of Tables and Figures

# 1. INTRODUCTION

The California Independent System Operator (CAISO) commissioned this study and report on California-centric barriers to demand response (DR) in response to the Federal Energy Regulatory Commission (Commission) Order 719. The study was directed by the CAISO and conducted by the consulting team of Freeman, Sullivan & Co. (FSC) along with Energy and Environmental Economics, Inc. (E3).

The study is designed to meet the requirements and directives of the Commission as ruled in Order 719 paragraphs 274-276. The core requirements of the Commission mandate are best provided through excerpts of the Order 719 Final Rule.

> *"274. The Commission adopts the requirement that each RTO or ISO assess and report on any remaining barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction and to submit its findings and any proposed solutions, along with a timeline for implementation, to the Commission within six months of the Final Rule's publication in the Federal Register. .*
> *275. … The report should identify all known barriers, and provide an in-depth analysis of those that are practical to analyze in the compliance time frame given and a time frame for analyzing the remainder…."*

The Commission also had several more specific requirements in terms of filing the report:

First, each RTO or ISO is required to "*ensure that minority views are adequately represented"* (paragraph 274), short of reporting every opinion of every individual stakeholder. As will be described herein, the approach to this study was designed to solicit stakeholder input in identifying the barriers as well as providing an approach to collect minority perspectives. The findings from a broad range of stakeholders are included in both the characterization of the barriers, as well as in the assessment of priorities and timelines.

Secondly, in paragraph 276, the Commission clarifies that the study may, but is not required to, consider energy efficiency and distributed generation within the scope of the study. This report does not address the issues of energy efficiency or distributed generation.

Finally, the Commission requires *"that each RTOs or ISO's Independent Market Monitor must submit a report describing its views on these issues to the Commission."* (paragraph 274) This consultant report will be provided to the CAISO Market Surveillance Committee (MSC), as well as the Department of Market Monitoring (DMM); their views will be provided to the Commission as a separate, independent submittal. At its discretion, the DMM/MSC may choose to reference this study in its report on demand response barriers to the Commission.

## 2. SCOPE OF STUDY

The California DR Barriers Study is designed to conform to FERC Order 719. In direct compliance with the Order, the consultant team defined the scope to:

- include all barriers to demand response from the perspectives of a broad range of participants including minority stakeholders;
- prioritize the barriers in consultation with the CAISO and the goals established by the Commission; and
- develop timelines for addressing each barrier.

The consultant team, with input from CAISO, defined additional criteria that were not specified by the Commission to narrow the scope and focus of the study.

First, and in keeping with the discussion contained in Order 719, the study focuses solely on California. While California faces many barriers that other RTOs and ISOs experience, the consultant team did not explicitly attempt to draw comparisons between California and other markets. At the same time, there are differences between California and other restructured markets. Primarily, California has an extremely active demand response portfolio that has (largely) operated independently of the CAISO markets and is funded through the California Public Utilities Commission (CPUC) and supported through state legislation. A number of the barriers pertain to the 'somewhat unique' California market and the misalignment of the regulatory-driven retail demand response programs with the wholesale energy market design.

Second, the study attempts to focus on 'barriers' as opposed to 'critical issues.' As the reader will note, this goal was elusive in that the consultant team and CAISO (with significant input from the stakeholders) came away with both barriers and what were deemed 'critical issues.' At a high level, 'barriers' are those challenges that rise to the level the consultant team and CAISO felt warrant attention and focus by the Commission (and key California stakeholders) while 'critical issues' center on important questions and details that can likely be resolved by the CAISO and its stakeholders with proper focus and attention. Most barriers are policy-based and at their root involve a fundamental policy conflict that must be resolved before the barrier can be eliminated. Most issues are process-based and while they may currently obstruct greater demand response participation, they hopefully can be resolved within the current CAISO stakeholder and working group processes or through an ongoing CPUC proceeding. An example of a barrier is that several participants in the study felt that the lack of a centralized capacity market in California would inhibit DR directly participating in the CAISO market in that they would not be able to tap into a significant and important "capacity" revenue stream necessary to build and fund DR resources. An example of a critical issue is the need for a market participant to establish appropriate back-office settlement protocols for direct participation of DR in the CAISO markets. The distinction between 'barriers' and 'critical issues' is somewhat subjective; there are several DR challenges that fall somewhere in-between. There is also a difference in perspective among stakeholders on whether a particular challenge is a barrier or an issue. In these cases, the consultant team and CAISO endeavored to focus on 'conflict in policy-based' barriers, but have erred on the side of including more barriers as well as critical issues rather than less.

Finally, a five year time horizon has been used in the assessment of the barriers. There are a number of initiatives underway in California including installation of Advanced Metering Infrastructure (AMI) for all customers, and deployment of default (with opt out provisions) dynamic pricing for commercial and industrial customers, that are currently scheduled to be completed by the end of 2012. In addition, the CAISO has planned the release of revised and new demand response products in the wholesale market, with an aggressive schedule of having them in place by summer 2010. There are also several regulatory initiatives underway at the CPUC, including the Demand Response Order Instituting Rulemaking (R.07-01-041). Therefore, the study focuses on barriers and critical issues that will impede DR in California, if not addressed, as these infrastructure, market, and regulatory initiatives roll-out over the next five years. If resolved, California will be better positioned to have a fully operational and well-tuned wholesale DR market by 2012.

# 3. APPROACH

In the development and execution of the study, the consultant team and the CAISO have endeavored to meet the goals of the Commission, in particular by (a) identifying barriers from the perspective of a broad range of participants including minority views, (b) prioritizing the barriers, and (c) providing high-level timelines to the Commission for resolution of the barriers, in as efficient a manner as possible and within the statutory timeline as established by the Commission.

In addition to the Commission goals, the CAISO asked the consultant team to make this study as relevant as possible to the ongoing initiatives designed to encourage DR in California so that it may serve as an input to other DR related initiatives and proceedings going on in California. If the report is successful in this regard, it will inform these other initiatives regarding current stakeholder perspectives on DR barriers and thereby contribute to the goal of resolving them.

With these goals, the consultant team approached the study in five sequential steps; (1) literature review and information gathering, (2) initial characterization of DR barriers, (3) interviews with key stakeholders, (4) a widely publicized webinar to present refined barriers, and gather subsequent stakeholder feedback, (5) prioritization of barriers and development of timelines and initiatives to address the barriers. Each step is described below in more detail.

## 3.1. Literature Review and Information Gathering

The first step for the consulting team was to gather as much relevant information as possible to perform the study. With the goal of efficiency in mind, the consultant team recognized that a considerable amount of work has been done on demand response barriers from a national perspective, as well as focused specifically on California. Key studies include the Assessment of Demand Response & Advanced Metering (December 2008) prepared by FERC Staff which provides a recent national perspective, and The State of Demand Response in California (April 2007) prepared by the Brattle Group for the California Energy Commission which provides a California perspective.

In addition to prior studies on DR barriers, the consultant team compiled a history of demand response in California from literature and their own experience, reviewed the DR programs proposed by the California investor-owned utilities (PG&E, SCE, and SDG&E), and attended CAISO demand response working group meetings. The history of DR in California is long and rich and provides much of the context for the current barriers of demand response in the State. Ultimately, the foundations of many of the barriers can be traced through the 30 year history of DR in California, the aftermath of the California Energy Crisis, and the challenges faced with aligning retail DR programs funded and authorized in customer rates by state authorities (both regulatory and legislative) and the newly launched CAISO wholesale MRTU markets.

Appendix A provides a bibliography of the literature considered in this study. In addition, this study includes a section on California's long DR history to provide context for the identified barriers; see Section 4.

## 3.2. Characterization and Development of Initial Barriers

The second step for the consulting team was to develop an initial list of barriers based on the literature review and information gathering. The initial list was organized into topic areas, and used to develop an interview guide that spanned the range of barriers using the following approach;

- Each barrier was categorized into one or more topic areas; ‘market’, ‘regulatory’, ‘customer participation, ‘technology and infrastructure’, and ‘operations and settlement’.
- Each barrier was given a timeline within which it might be addressed; short-term (1 to 2 years), medium-term (within 4 to 5 years), and long-term (longer than 5 years), and
- Each barrier was categorized as something that FERC / CAISO could either address directly, influence the outcome as a ‘decision-shaper’, or had limited to no impact.

The final list of prioritized barriers presented in the study has evolved significantly from the initial list. Subsequent interviews with key stakeholders, as well as the discussion and feedback from the public webinar, has (a) refined and focused the list of barriers, (b) clarified some of the specific challenges for each, (c) redefined and expanded the number of topic areas used to categorize the barriers, and (d) contributed to the relative priority ranking of DR barriers that was absent in the initial list.

## 3.3. Interviews with Key Stakeholders

The third step for the consulting team was to conduct interviews with key stakeholders. The interview process was designed to get unfiltered and honest opinions from a cross-section of stakeholder organizations which would then provide the material for the webinar and open public feedback from any interested parties.

To facilitate the interviews, the consultant team prepared an ‘interview guide’ that was provided to each of the stakeholders prior to the interview itself based on the initial list of barriers. This guide is included as Appendix B. The guide includes specific questions for different types of stakeholder organizations, but all interviewees were allowed to provide their comments on any of the questions. In addition to the specific questions, each interviewee was asked a broader set of concluding questions and was encouraged to identify barriers not called out by the consulting team.

In order to help receive unfiltered and honest opinions, the identity of the specific interviewees is confidential. Overall, the consulting team conducted 13 interviews with over 30 individuals that span the range of involved stakeholder organizations. Each interview lasted approximately two hours. The organization types include California utilities, representatives of other load-serving entities, local regulatory authorities, ratepayer advocates, direct market participants, and customer representatives, and curtailment service providers (CSPs). To ensure accuracy, the content of the interviews was either recorded and transcribed, or captured through written notes by the consulting team. However, the specific discussion of all interviews has been kept confidential within the consulting team, and not provided to the CAISO or any other organization. These ground rules allowed each stakeholder to freely express their opinion on specific barriers without attribution. At the same time, public discussion and feedback of the characterization of the barriers by the consulting team in the webinar allowed for a check on the accuracy in capturing stakeholder comments.

## 3.4. Webinar to Discuss Results

The fourth step was to conduct a public webinar, hosted by the CAISO, designed to walk-through the refined list of barriers compiled from the interviews. The webinar was held on April 8, 2009 and was publicized through a CAISO market notice and listed on the CAISO website.[7]

Overall, there were 50 participants in the webinar. Approximately 50% of the two hour webinar was dedicated to background information and discussion of barriers identified by the consulting team during interviews, and the remaining 50% was dedicated to discussion and clarification by stakeholders. The presentation used in the webinar is included as Appendix C. In addition to the feedback provided directly in the webinar, stakeholders were asked to provide the CAISO and consulting team with written comments.[8] Comments were received from nine (9) parties and incorporated into the final characterization of the barriers in the study. In addition, many of the criticisms shared as a result of the webinar had to do with material presented on a specific slide within the webinar deck. Therefore, the webinar deck contained in Appendix C contains all the respondents' specific comments on a slide by slide basis. The respondents' more general comments are contained in Appendix D.

## 3.5. Prioritization of Barriers and Identification of Solutions

The fifth step, once the public process to involve stakeholders was complete, was to work in close consultation with the CAISO to prioritize the barriers and identify solutions and timelines to each.

Two primary criteria were used to assess and prioritize the barriers. The first criterion is the degree to which the barrier inhibited comparable treatment of generation and DR resources. The resource comparability criterion is taken directly from the ruling by the Commission in Order 719. The second criterion was the degree to which the barrier inhibited the pursuit of California's DR Vision and the call for increased participation of demand response in the CAISO markets. This criterion is based on the CAISO's position in support of the DR Vision and demand response in California. Using these criteria, the consulting team assessed and subjectively assigned a combined ranking of 'high', 'medium', or 'low' to each barrier.

With the prioritized list of barriers in hand, the consulting team worked in consultation with the CAISO to identify solutions and establish timelines for their resolution. In many cases, the identified barriers fall within the scope of ongoing California demand response initiatives and working group processes. In these cases, the timeline associated with the initiative has been used as the appropriate timeline to address the barrier. In these cases, the findings of this study can help provide greater definition and specificity on the barriers in these proceedings. This is also consistent with the CAISO goal of informing and contributing to the various DR initiatives in California. In other cases, new activities

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[7] http://www.caiso.com/1893/1893e350393b0.html
[8] Comments were requested to be provided by COB Friday, April 17, 2009.

by the CAISO are identified that can help resolve demand response barriers.  The study has endeavored to define a path to resolve all of the barriers identified.

# 4. HISTORY OF DEMAND RESPONSE IN CALIFORNIA

California has a long history of demand response, a robust set of DR programs managed by the IOUs, and a broad set of engaged stakeholders. California's legacy in demand response provides context for many of the regulatory, market and customer barriers identified in this study.

California has a 30 year history of load management programs including interruptible rates and direct load control programs implemented by the utilities. By the 1990's, the utilities had successfully enrolled approximately 5% of peak demand in demand side management programs. In 1996, the California legislature passed AB 1890, *The Electric Utility Industry Restructuring Act*, which created a competitive electricity market. At that time, the programs had enrolled 2,800 MW of dispatchable peak demand.[9] The popularity of these programs was partially due to their history of limited use by the utilities. Before 2000, the programs were rarely used and considered an "insurance policy" in combination with integrated resource planning which insured California's comfortable reserve margins.[10] However, due to restructuring, the state's resource planning processes were limited and the capacity margins began to shrink.

Forecasting a need for significant additional curtailable load, the CAISO began development of new demand response programs in 2000. Two different programs were rolled out - the Participating Load Program and the Demand Relief Program. The Participating Load Program was designed as a market-based offering where loads would compete with generation in the ancillary services market. The Demand Relief Program provided fixed payments for load curtailment based on system conditions. Neither of the programs reached their enrollment goals in 2000.[11] Notably much of the load that did enroll in the Participating Load Program could not actually participate because the CPUC determined that customers should not be able to participate in both the CAISO and the utility programs simultaneously. During the energy crisis, the utility programs required high levels of participation in order to reduce the number of blackouts. In the last eight months of 2000, the enrolled entities were asked to curtail 23 times.[12] The participating customers were not prepared for this level of curtailment given the limited historical number of operations; many opted out of the program in 2001. This reduced the total program level to less than half the level of participation seen in 1998, 1999 and 2000.

[9] A Critical Examination of ISO-Sponsored Demand Response Programs: A White Paper. Grayson Heffner. Freeman Sullivan. August 2005. http://www.fscgroup.com/news/FSC_DRWhitePaperHeffner.pdf

[10] Charles A. Goldman, Joseph H. Eto, and Galen L. Barbose, "California customer load reductions during the electricity crisis: Did they help to keep the lights on?" (May 1, 2002). *Lawrence Berkeley National Laboratory.* Paper LBNL-49733. http://repositories.cdlib.org/lbnl/LBNL-49733

[11] Overview of California ISO Summer 2000 Demand Response Programs. John H. Doudna, P.E, Senior Member, IEEE California 1S0 Operations Engineering Dept. IEEE. 2001.

[12] (2001b). "Energy Division's Report on Interruptible Programs and Rotating Outages." Filed with the California Public Utilities Commission under Proceedings for R. 00-10-002, February 8.

Thus, the electricity crisis in 2000 and 2001 tested the legacy demand response resources and forced the CAISO and the CPUC to rethink their demand response products. The DR programs created for the summer of 2001 offered a wide range of new program design concepts. These programs were outlined in an LBNL overview report of the crisis written by Goldman, Eto and Barbose in May of 2002; a program summary table from their report is shown below. [13]

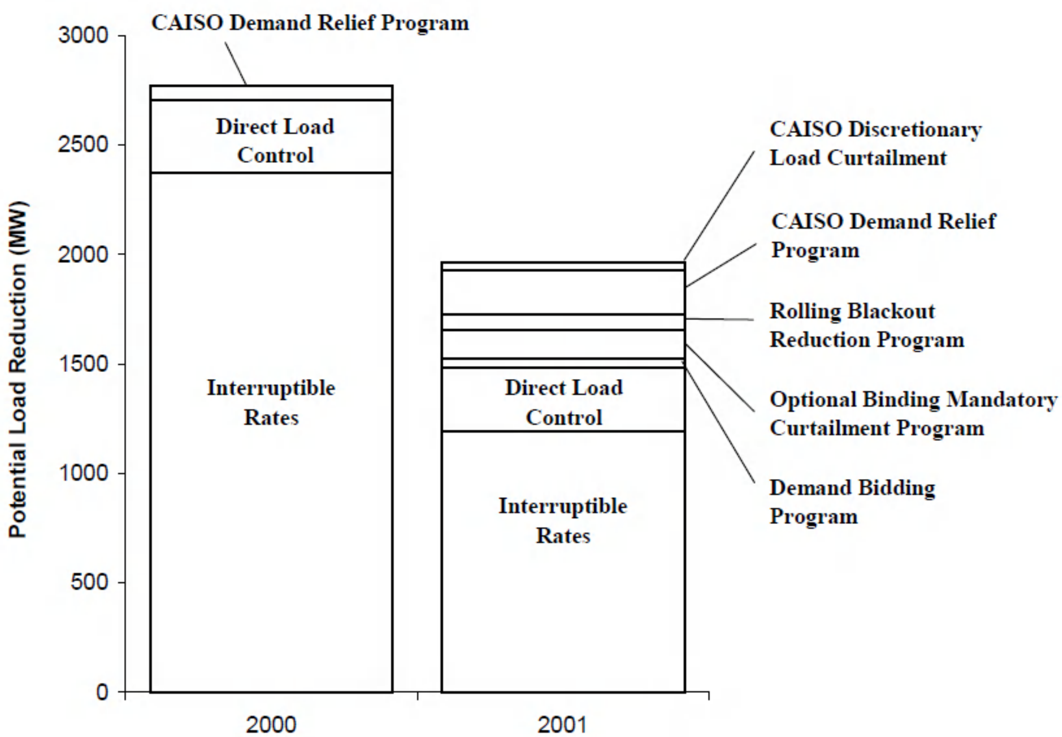
**Table 7: 2001 DR Programs**

| Program Name | Program Administrator[a] | Description | Operational Trigger | Incentive Amount |
|---|---|---|---|---|
| Interruptible Rates and Base Interruptible Program | IOU | Participants commit to reduce to Firm Service Level (FSL) upon notification. | Contingency | ~$7000/MW-month |
| Direct Load Control (A/C Cycling and Agricultural Pumping) | SCE | Customer agrees to allow utility to interrupt air conditioning or agricultural and pumping loads. | Contingency | $0.014 - 0.40/ton-day |
| Optional Binding Mandatory Curtailment (OBMC) | IOU | Participants commit to curtail at least 15% of the circuit load during every rotating outage. | Contingency | - |
| Demand Bidding (DBP) | IOU | Participants bid load reductions day-ahead, through DBP Web-site. | Market | $100 - $750/MWh |
| Scheduled Load Reduction (SLRP) | IOU | Participants provide weekly load reductions in four-hour blocks on specific days. | Pre-scheduled | $100/kWh |
| Rotating Blackout Reduction Program (RBRP) | SDG&E | Participants run Back-Up Generators during all rolling outages | Contingency | $200/MWh |
| Demand Relief Program (DRP) | CAISO | Participants provide a pre-specified load reduction upon notification by CAISO. | Contingency | $20,000/MW-month and $500/MWh |
| Discretionary Load Curtailment Program (DCLP) | CAISO | Participants offer voluntary load reductions in response to requests by CAISO. | Contingency | $350/MWh |

Most of the new programs were based on reliability, but some were market incentive based such as the new demand bidding program. While the CPUC and CAISO hoped these programs would provide more flexibility and increase enrollment, the number of choices and constant changes appeared to confuse customers. In addition, according to the LBNL report, while the CAISO was initially successful at signing up load aggregators, it was unable to guarantee prompt payment which resulted in significant attrition from its programs. Combined, the CAISO and CPUC (through the utilities) enrolled 1,900 MW in their 2001 programs. However, the programs were only called on once to provide 800MW. The load curtailment required in 2001 was largely met with other voluntary customer load reductions. Figure 1 below from the 2002 LBNL report shows the drop in enrollment and the distribution of participation in the new programs.

[13] Charles A. Goldman, Joseph H. Eto, and Galen L. Barbose, "California customer load reductions during the electricity crisis: Did they help to keep the lights on?" (May 1, 2002). *Lawrence Berkeley National Laboratory.* Paper LBNL-49733. http://repositories.cdlib.org/lbnl/LBNL-49733

**Figure 1: Comparative and Participation in DR Programs** [14]




After the electricity crisis, management of the demand response resources shifted to the CPUC and the investor-owned utility programs. The CAISO deemed it "prudent to scale back its efforts and defer to the CPUC, the CPA (California Power Authority), and the IOUs to develop programs and provide program funding." [15] The CAISO reported in their annual 2001 report that the result of the 2000-2001 energy crisis was a significant decline in customer interest in demand response programs, which was due to "payment concerns, extensive curtailment of loads on the interruptible rate tariff, regulatory uncertainty, a large number of different, competing programs, and ongoing revisions to those programs". The CAISO also stated that demand response programs would not succeed without coordination between state agencies.[16]

Control of the majority of demand response programs shifted to the CPUC under Assembly Bill 57, which Governor Davis signed in September 2002. The bill provided the regulatory framework for utilities to again procure electricity supplies and demand reductions, as well as to develop long-term procurement plans[17]. In October 2002, the CPUC determined that the IOUs should take responsibility for procuring sufficient resource to maintain the reliability of California's electric grid. This decision also

[14] Ibid. p. 9

[15] A Critical Examination of ISO-Sponsored Demand Response Programs: A White Paper. Grayson Heffner. Freeman Sullivan. August 2005. http://www.fscgroup.com/news/FSC_DRWhitePaperHeffner.pdf

[16] CAISO Annual Report, 2001

[17] "Measurement and evaluation of energy efficiency programs: California and South Korea". E. Vine, C.H. Rhee, and K.D. Lee. Energy 31 (2006) 1100–1113

indicated that 'resource adequacy should first be met through all cost-effective energy efficiency and demand-response programs.'[18]

In April 2003, the CPUC, CEC, and the California Power Authority prepared the Energy Action Plan (EAP), which presented a unified energy policy outlook and emphasized energy efficiency to meet California's energy needs. The demand response goal developed in the EAP in 2003 was set as achieving price-sensitive price demand response capacity of 5% of annually peak loads by 2007.[19] The EAP also adopted a "loading order" to meet electricity needs. The California state policy is to meet increased load first with energy efficiency and demand response; second, with renewable energy and distributed generation; and third, with clean fossil-fueled sources.

Then in early 2004, the CPUC adopted a framework for integrated resource planning and resource adequacy for the three investor-owned utilities.[20] In a subsequent decision, the CPUC identified the need to develop M&E protocols and cost-effectiveness methodologies for retail demand response programs and tariffs in 2005.[21] In 2006, the CPUC created several new retail demand response programs to increase participation.[22] From 2006-2008, the CPUC approved the installation of Advanced Metering Infrastructure (AMI) for the investor-owned utilities, including interval meters for all customers and supported the development of critical peak pricing (CPP) as the default tariff (with opt out options) for commercial and industrial customers. These recent changes are seen as a way to move towards real-time pricing and achieve greater levels of demand response.

[18] California Public Utilities Commission. Decision 02-10-062. Interim opinion, Oct 24, 2002. San Francisco, CA: CPUC; 2002. http://docs.cpuc.ca.gov/published/Final_decision/20249.htmWeb site: www.cpuc.org.

[19] The document "California Demand Response: A Vision for the Future (2002-2007)" is included in D.03-06-032 as Attachment A. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/26965.ht

[20] California Public Utilities Commission http://www.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/33555.htm

[21] CPUC Decision: D.05-11-009

[22] California Public Utilities Commission http://www.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/62260.htm

# 5. CURRENT DEMAND RESPONSE LANDSCAPE

Given the history of DR in California, the state is well positioned to take advantage of retail demand response resources. The CPUC, IOUs and CAISO have years of experience operating demand response programs and the state legislature and regulatory authorities are motivated to promote having demand response products for customers. For instance, the utilities include long-range forecasts of demand response in their Long-Term Procurement Plans (LTPP) and the CPUC allows the megawatts associated with retail demand response programs to count towards meeting CPUC jurisdictional load serving entities' resource adequacy requirements. In addition, by funding the installation of an advanced metering infrastructure in much of California, a critical foundation will have been laid that will hopefully enable greater participation of demand response resources in the wholesale electricity markets. The state also has seasoned DR aggregators and a high level of demand response awareness among its commercial and industrial customers, especially when it comes to reliability-based demand response. Since the challenges faced during the energy crisis, demand response has grown substantially over the past five years and more products are now "price-responsive."[23] The growth in participating demand response load from 2003 through the proposed 2009 IOU DR programs is shown in Table 8 below.

**Table 8: MWs in Utility Demand Response Programs**

| | July 2003 (MW)[24] | July 2005 (MW)[24] | April 2008 (MW)[24] | Proposed 2009 (MW)[25] | 5% DR Goal (MW) |
|---|---|---|---|---|---|
| **Price Responsive Programs** | 0 | 850 | 1,136 | 1,287 | 2,500[26] |
| **Reliability Programs** | 1,485 | 1,600 | 1,850 | 1,498 | N/A |

However, multiple authorities are involved in demand side management in California, complicating the DR market. The CPUC, CAISO, CEC, IOUs, and the State Legislature have all staked out active roles in the development of demand response in California. There is a dual market structure for DR in the state; part regulatory driven with programs funded by the CPUC and implemented by the IOUs, and part market driven with the participation of DR in wholesale energy markets managed by the CAISO. This dual market is somewhat unique to California and has developed partly in response to the historical load management programs and to the electricity crisis of 2000-2001.

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[23] The demand response goals were clarified in D.05-01-056. Price-responsive tariffs and programs were categorized as day-ahead. Reliability programs (interruptible; load control) were categorized as day-of.

[24] Enrollment is defined by "Upper-bound" estimates – represents highest potential load drop. Actual results may vary. **Source:** CPUC: Bruce Kaneshiro presentation June 23, 2008

[25] 2009-2011 Demand Response Program Filings. CPUC Application 08-06-001, 08-06-002, 08-06-003. Filed June 2, 2008. Not including pilot programs or educational initiatives.

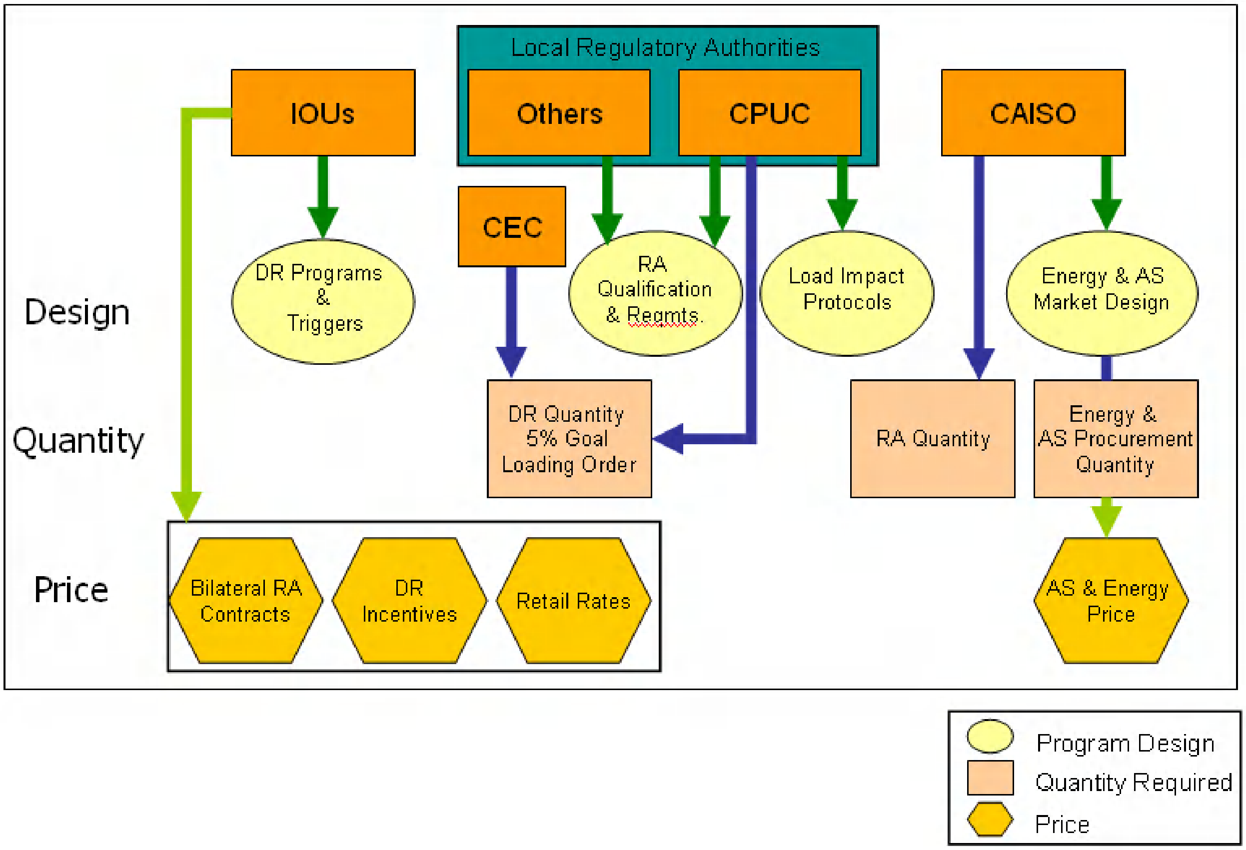
[26] 5% of an assumed 50,000 MWs of system peak demand – illustration purposes only.

These entities guide the program design; determine quantity requirements to meet resource adequacy, energy needs and policy goals; and create the incentives and market rules that provide a price signal to the retail end consumer. An overview of the multiple entities that direct program designs, set enrollment goals and determine rate and incentive levels is shown in Figure 2. The CPUC has established Resource Adequacy guidelines. The CPUC as well as other Local Regulatory Authorities, determine RA qualifications and requirements of the utilities throughout the state. The amount of RA capacity required in each Local Area is determined by studies performed by the CAISO. The utilities are then responsible for procuring the RA capacity through individually negotiated bilateral contracts or RFPs.

The CPUC and the CEC jointly developed the 2005 Energy Action Plan that put energy efficiency and DR at the top of the preferred loading order and set a goal of enrolling 5% of load in DR programs. The CPUC on its own has also implemented DR load impact protocols and cost-effectiveness criteria to be used by the utilities in evaluating their programs. The utilities design and implement multiple DR programs, submitting proposed programs every three years for review and approval by the CPUC. The utilities propose the level and type of incentives for DR programs, as well as the rates for retail customers, with CPUC oversight and approval.

The CAISO is responsible for the specifications and requirements of the energy and ancillary services products needed to operate a reliable transmission system. The CASIO designs and implements the wholesale markets for those products with oversight from FERC.

**Figure 2: California 'Hybrid' DR Market: Program Design, Quantity, and Value**




Aside from determining capacity requirements and operating wholesale markets, the CAISO has a relatively limited role in the current DR portfolio. This is due to the influence of the electricity crisis and the return to CPUC-regulated utility demand response programs. In addition, the CEC and CPUC have expanded their efforts under the direction of the Energy Action Plan in order to meet the five percent peak load demand response goal.

The CAISO currently operates two demand response programs - the Voluntary Load Reduction Program (VLRP) and the Participating Load Program (Ancillary Services /Supplemental Energy). The VLRP is a purely voluntary program where participants reduce their energy consumption when the California ISO declares a power emergency. The CAISO cannot rely on a firm output from this voluntary program. The Participating Load Program allows loads to participate as price-responsive demand in the CAISO's energy and ancillary services markets. The California Department of Water Resources (CDWR) is the only participant in the PLP and actively manages 2,500 MW of load in PLP (3,000 MW including pumped storage).

While the PLP program is large in terms of enrolled MWs, the vast majority of the customers participating in demand response are enrolled in IOU demand response programs. In 2007, the CAISO programs represented 4% of the demand response enrollments (3% in the PLP reliability program and 1% in the VLRP). The IOUs programs covered the bulk (96%) of the enrollment with 58% enrolled in the interruptible reliability-based programs and 38%[27] in price-based programs.[28]

Given the duality of the DR market, the CAISO system needs and wholesale prices may not align well with the regulatory-driven retail program incentive levels and dispatch triggers. The dispatch of the regulatory DR programs is managed by each IOU, each with somewhat different trigger mechanisms. The rule based trigger types fall into three different categories; 1) emergency alerts issued by the IOUs or CAISO, 2) implied market or actual system heat rates, and 3) forecasted peak loads. In addition, many programs may be dispatched at the discretion of the utility, with a limit on the frequency and duration of calls per month or year.

The trigger mechanisms for the proposed 2009-2011 DR programs of PG&E, SCE and SDG&E are shown in Table 9,Table 10 and Table 11 respectively. In some cases, the program title represents an umbrella program for a number of smaller programs. In other cases, the IOU contracts with a CSP to implement one or more programs, with the CSPs having varying degrees of flexibility in defining program incentives. The tables also show whether the utilities categorize the program as a reliability (i.e., emergency) program or a price responsive program.[29]

**Table 9: PG&E DR Programs 2009-2011**

| | MW Impact 2009 | Price or Reliability Basis | Trigger Mechanism | | | | |
|---|---|---|---|---|---|---|---|
| | | | Alert | Heat Rate | Temp Forecast | Peak Forecast | IOU/CAISO Decision |
| PeakChoice | 36 | Price | √ | √ | √ | √ | √ |
| Critical Peak Pricing (CPP) | 20 | Price | | | √ | | |
| Capacity Bidding Program (CBP) | 18 | Price | | √ | | | |
| Demand Bidding Program (DBP) | 8 | Price | √ | | | √ | |
| Automated Business Energy Coalition Program (ABEC) | 2 | Price | | | | | |
| SmartRate | 52 | Price | | | √ | | |
| Permanent Load Shifting | 2 | Price | | | | | √ |
| Aggregator Managed Portfolio (AMP) | 125 | Price & Reliability | √ | √ | √ | √ | √ |
| Base Interruptible Program (BIP) | 260 | Reliability | √ | | | | |
| SmartAC | 152 | Reliability | | | | | √ |
| CDWR Agreement | 200 | Reliability | | | | | √ |
| DR Program Total | 875 | | | | | | |

[27] Per According to the 2009-2011 Demand Response Program Filings. (CPUC Applications 08-06-001, 08-06-002, 08-06-003. Filed June 2, 2008), 54% of the enrolled MWs for 2009 are expected to come from reliability Programs and 36% are expected from price responsive programs.

[28] FERC Assessment of Demand Response and Advanced Metering Report. Figure II-1 (2007)

[29] The tables do not include pilot programs or education or technology assistance based initiatives

**Table 10: SDG&E DR Programs 2009-2011**

| | MW Impact (1 in 2) 2009 | Price or Reliability Basis | Trigger Mechanism | | | | |
|---|---|---|---|---|---|---|---|
| | | | Alert | Heat Rate | Temp Forecast | Peak Forecast | IOU/CAISO Decision |
| Default Critical Peak Pricing (CPP-D) | 58 | Price | | | √ | √ | √ |
| Peak Time Rebate Program (PTR) | | Price | | | √ | √ | √ |
| Capacity Bidding Program (CBP) | 18 | Price | | √ | | | √ |
| Summer Saver Program | 20 | Price | | √ | | √ | √ |
| Permanent Load Shifting | 1 | Price | | | | | √ |
| Emergency Critical Peak Pricing (CPP-E) | 3 | Reliability | √ | | | | √ |
| Base Interruptible Program (BIP) | 5 | Reliability | √ | | | | |
| Total | 105 | | | | | | |

**Table 11: SCE DR Programs 2009-2011**

| | MW Impact 2009 | Price or Reliability Basis | Trigger Mechanism | | | | |
|---|---|---|---|---|---|---|---|
| | | | Alert | Heat Rate | Temp Forecast | Peak Forecast | IOU/CAISO Decision |
| DR Contracts (approved) | 100 | Price | √ | √ | √ | √ | √ |
| DR Contracts (proposed) | 106 | Price | √ | √ | √ | √ | √ |
| Real Time Pricing > 200 kW | 28 | Price | | | √ | | |
| Energy Option Plan | 65 | Price | | | | | √ |
| Critical Peak Pricing (CPP) >200kW | 12 | Price | | | | | √ |
| Permanent Load Shifting | 2.4 | Price | | | | | √ |
| Summer Discount Plan | 613 | Price & Reliability | √ | | | | √ |
| Base Interruptible Program | 687 | Reliability | √ | | | | |
| Agriculture & Pumping - Interruptible | 58 | Reliability | √ | | | | |
| Optional Binding Mandatory Curtailment (Stage 3) | 9 | Reliability | √ | | | | |
| Total | 1,680 | | | | | | |

Looking at the IOU's actual calls for curtailment associated with the Capacity Bidding Program (CBP) illustrates the historic relationship observed between utility program triggers and CAISO wholesale markets. The Capacity Bidding Program is a price-based DR program with a heat rate based trigger (i.e., when the utility would use fossil-based generation with a heat rate greater than 15,000 Btu/kWh). The utility CBP calls (i.e., operations) for 2007 are plotted against CAISO system load in Figure 3 and the higher of the zonal NP15 or SP15 price in each hour in Figure 4. In each case, many of the calls do occur during the hours with the highest load or prices. However, many calls occurred during hours with more moderate loads and prices. Some of the mismatch is certainly due to having to call programs based on forecast conditions, and calling them for a block of 4-6 hours at a time. It is probably also the case, however, that the heat rate triggers used in each IOU's service territory are not always correlated with periods of high CAISO system loads and prices.

**Figure 3: IOU CBP Calls Plotted Against CAISO System Load Duration Curve (2007)**

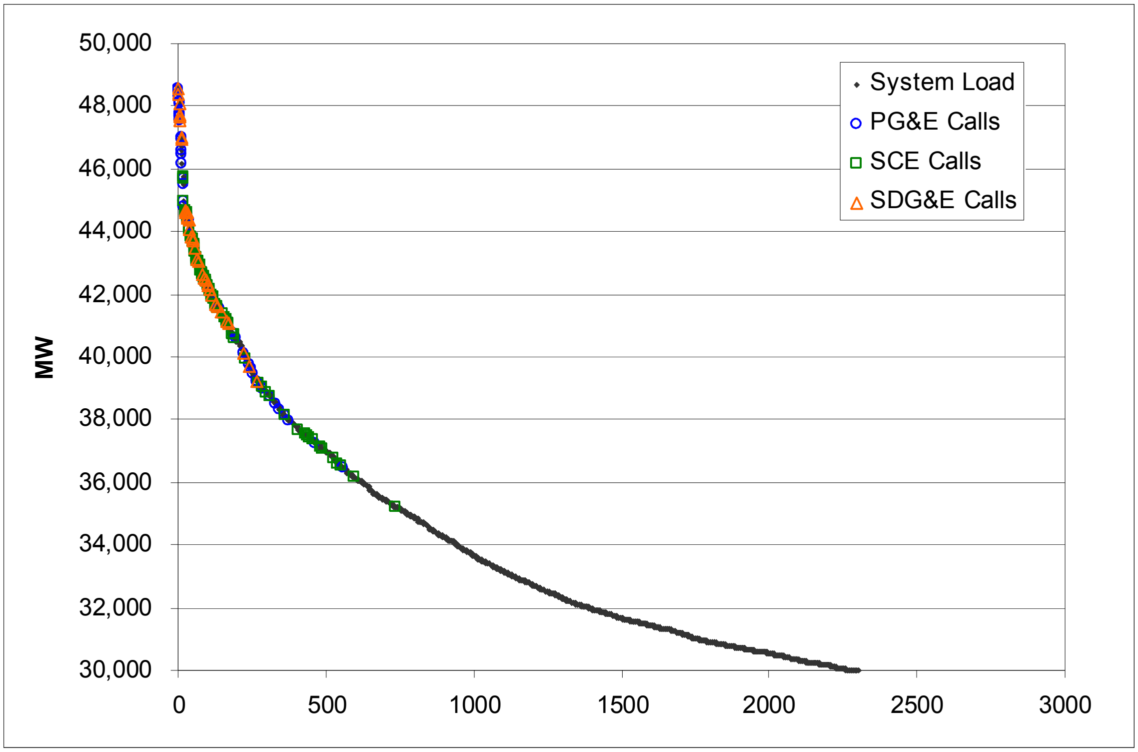
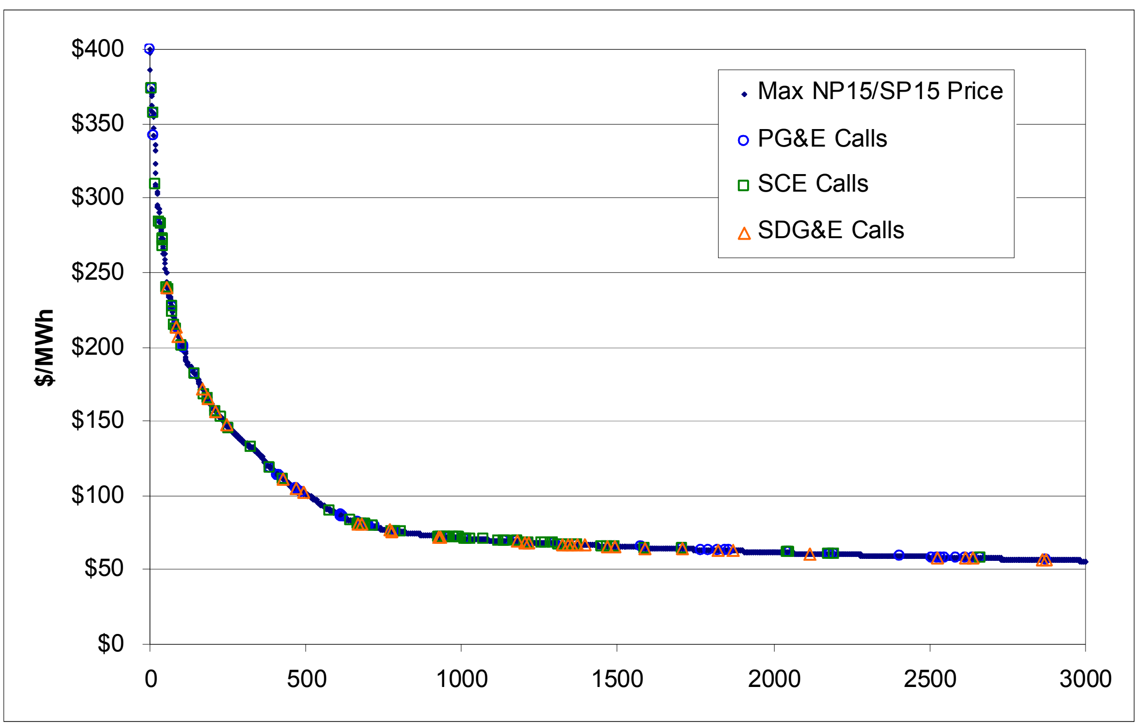
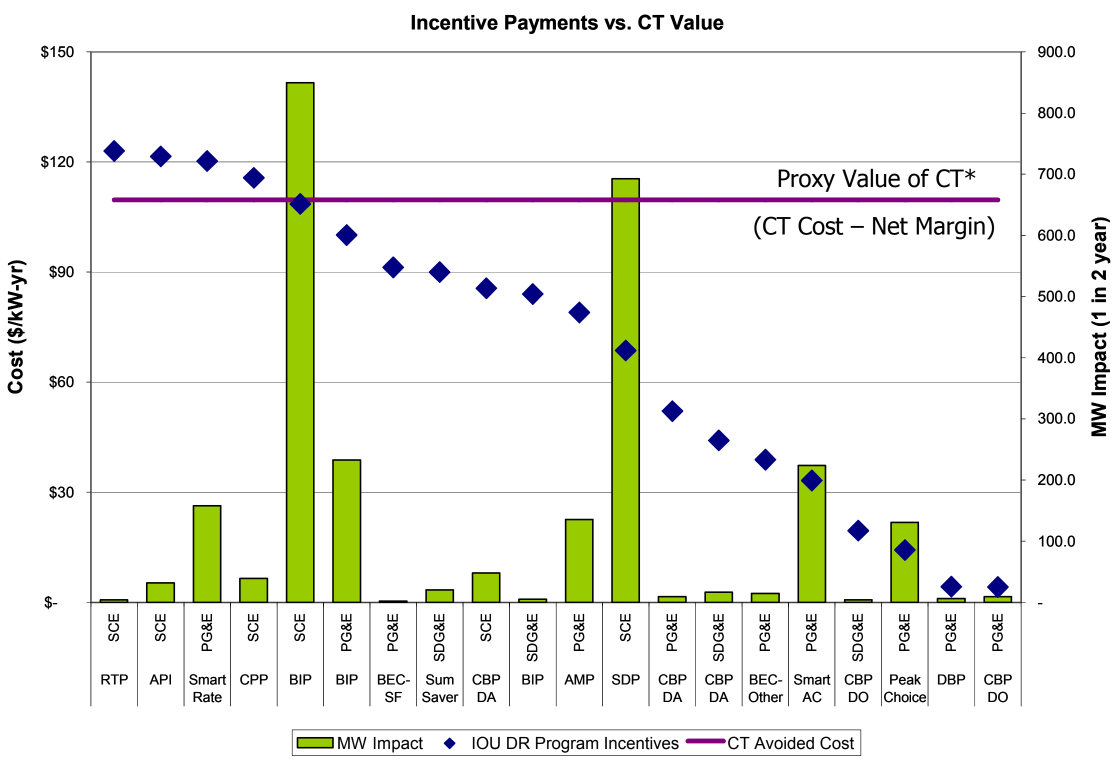



**Figure 4: IOU CBP Calls Plotted Against Max NP15/SP15 Price Duration Curve (2007)**



Like many of the dispatch triggers, the incentives for retail DR program participation are not linked to the CAISO markets, or the utility procurements of resource adequacy (RA). The existing IOU demand response programs have been influenced by the 30 years of CPUC-approved programs that were implemented by the IOUs. Some of the existing DR programs have very attractive incentives that DR participants have become accustomed to receiving. Figure 5 below shows a subset of the IOU 2009-2011 demand response programs with forecasted incentive costs ($/kW-yr) and estimated impacts (MW). For comparison, the incentive costs are compared to the net cost of new entry (CONE) for a combustion turbine unit after calculating gross margins ($/kW-yr).[30] The incentive costs are calculated as the total incentive payments (including capacity, energy and lump sum payments) divided by the expected kW impact. The achieved impact varies according to anticipated performance. Figure 5 shows that the program incentives costs vary dramatically per kW of impact, with some programs above the CAISO CONE estimate.

**Figure 5: Sample of IOU DR Program Incentives**




** CAISO 2008 Market Assessment Report*

In summary, the California market has a fairly robust and expanding portfolio of regulatory-driven DR programs that are a mix of price-based and reliability-based designs. These programs are funded through the retail rates authorized by the CPUC,

[30] 2009-2011 Demand Response Program Filings, including programs for which incentive level and impact estimates were available. Data was not available for other 2009-2011 demand response programs.

and therefore the payments and operational rules for the DR programs are not directly linked to either the CAISO DR products or LSE resource adequacy procurements. That said, the programs appear to operate during high load times, and during the periods of highest prices. While the incentives range widely, most programs are designed to reduce critical summer peak loads and have incentive payments in the range of the cost of a new CT or less. Furthermore, as described in the next section, the CPUC is actively addressing the comparability issues in the DR programs in its DR OIR (CPUC R.07-01-041) and the CAISO is actively participating as a stakeholder in this process.

# 6. DEMAND RESPONSE INITIATIVES IN CALIFORNIA

The current DR portfolio in California is in an active state of transition. The regulatory-driven DR portfolio approved by the CPUC and managed by the IOUs is being rebalanced to include more price-based DR. This shift is a direct result of the California policy goals, expressed in the Energy Action Plan and the Joint DR Vision, to encourage price-based demand response. There are a number of initiatives underway to encourage the transition, primarily;

1. The three IOUs (PG&E, SCE, and SDG&E) are installing Advanced Metering Infrastructure (AMI)
2. The three IOUs are phasing in default (with opt out provisions) dynamic pricing for commercial and industrial customers
3. The 2009-2011 program plans filed by the three IOUs are actively expanding price-based DR programs and are working towards greater integration with CAISO markets
4. Resolving DR related issues due to the enactment of California Assembly Bill 1X

At the same time, the CAISO launched MRTU on March 31, 2009 which provides locational marginal prices throughout the control area and also includes a Participating Load demand response product. To facilitate the participation of the aggregated IOU and CSP DR programs in the new market design, the CAISO and involved stakeholders developed a new proposed Proxy Demand Resource (PDR) product with a planned release in May of 2010. The CAISO is also doing research on a range of DR technologies and the ability to automatically coordinate demand and supply side resources in its DR365 lab. The goal is to move DR in California beyond the few critical peak and high priced hours.

If successful, the infrastructure investments and retail pricing changes authorized by the CPUC, and the launch of MRTU and direct participation DR products accessible to the IOUs, will succeed in increasing the amount of price responsive load. There are a number of stakeholder processes, including the CPUC DR OIR, the CPUC Resource Adequacy proceedings, and the CAISO stakeholder process and working groups that are designed to support their respective components of the overall process.

Each of these initiatives is described in more detail below.

<u>Resolving DR related issues due to the enactment of California Assembly Bill 1X</u>
During the energy crisis, in February 2001, the California Legislature enacted AB1X. AB1X authorized the California Department of Water Resources (DWR) to purchase power and sell it to retail customers on behalf of utilities in California. In its role managing the State Water Project (SWP), DWR is a large consumer and producer of power, and with the financial resources of the state, DWR could enter into power purchase agreements that the financially distressed utilities could not. To insulate residential customers from further rate increases resulting from the energy crisis, AB1X capped electric rates for the first two tiers (up to 130% of baseline usage) at February 1, 2001 rate levels. The rate cap is to remain in place until the costs of the DWR power contracts are fully recovered. The AB1X rate cap restricts the ability of the CPUC or utilities to implement anything but voluntary dynamic or CPP rates. As a result, default

dynamic rates have been limited to non-residential customers. This has caused some complaints from commercial and industrial customers, who hold that they have already shouldered a disproportionate share of increases in energy costs since AB1X was enacted. Ratepayer advocates argue, on the other hand, that non-residential customer classes enjoyed a disproportionate share of the benefits under deregulation.

The CPUC is currently exploring various ways to accelerate lifting the AB1X rate cap, including the novation and assignment of existing DWR contracts. However, there remains considerable uncertainty and controversy regarding the legal risks, costs and benefits as well as how to structure an achievable schedule for the various options.

AB1X also allows ESPs to continue to serve existing DA customers, but prohibits enrollment of new customers. The CPUC has not yet considered to what extent CSPs are similar to, or distinct from, ESPs as it relates to the prohibition against the expansion of DA. The issue of whether an ESP can also act as a CSP has also not yet been addressed by the CPUC. The CPUC is currently considering whether these issues constitute a state rule or regulation that in effect prohibits direct participation of DR in CAISO markets, per Order 719.

<u>Advanced Metering Infrastructure</u>

California has been pursuing smart metering since 2001 when the state legislature appropriated $35 million for customers with greater than 200 kilowatts of load to have their utility install interval meters. Since then, the CPUC required mandatory TOU rates for all customers with maximum demand greater than 200 kW who received new meters via the California Energy Commission's funding (see Dynamic Pricing below).[31] As a result of these past policies, the vast majority of large C&I customers have been on TOU for over five years, and some have been on TOU for as long as 30 years.

In recent years, California has expanded its metering efforts with the rollout of the Advanced Metering Infrastructure (AMI) initiatives at the three investor-owned utilities. Advanced meters are defined by the U.S. Department of Energy as “a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and provides for daily or more frequent transmittal of measurements over a communication network to a central collection point.”[32] The metering infrastructure installation is underway and is planned to be complete by 2012. Table 12, below, summarizes the AMI spending authorized for each utility, the planned completion date, the number of meters to be installed and a summary of the selected technology for each of the three utilities.

[31] *See* D.01-05-064 as modified by D.01-08-021 and D.01-09-062.

[32] 2008 Assessment of Demand Response and Advanced Metering. Federal Energy Regulatory Commission.

**Table 12: Advanced Metering Infrastructure Funding, Technology, and Timeline**

| | Spending Authorized | Date Complete | Technology overview |
|---|---|---|---|
| PG&E[33] | $2.16 B | 2012 | 5.1 million electric meters. 4.2 million gas meters. Technology: GE SmartMeters and Landis+Gyr electric meters. Software: Silver Spring Networks for electric meters and Aclara for gas meters |
| SCE[34] | $1.63 B | 2012 | 5.3 million meters. Technology: Itron's OpenWay CENTRON meter Software: Edison SmartConnect™ |
| SDG&E[35] | $581M | 2011 | 1.4 million electric meters 900,000 gas meters. Technology: Itron OpenWay Meters Software: Itron Enterprise Edition™ Meter Data Management |

The funding for the AMI initiatives were partially justified based on the economic benefits derived from enabling demand response capability. The majority of the benefits were calculated as operational and meter reading cost reductions. However, all three utilities used demand response benefits in their applications of AMI cost-effectiveness to cover the gap between long-term benefits and costs. In its initial filing, PG&E projected that it could cover 90% of AMI costs with operations and meter reading. SDG&E met 80% and SCE met 65% through operational improvements. PG&E made a second funding request to purchase additional two-way communicating capabilities in its proposed system. In PG&E's second request for AMI funding, the cost upgrades were almost entirely covered by demand response and conservation benefits. Figure 6 shows the comparison of projected cost and benefits for the three utility AMI programs and shows the level of demand response necessary to cover the gap. Note that the graph normalizes benefits relative to 100% of the cost.

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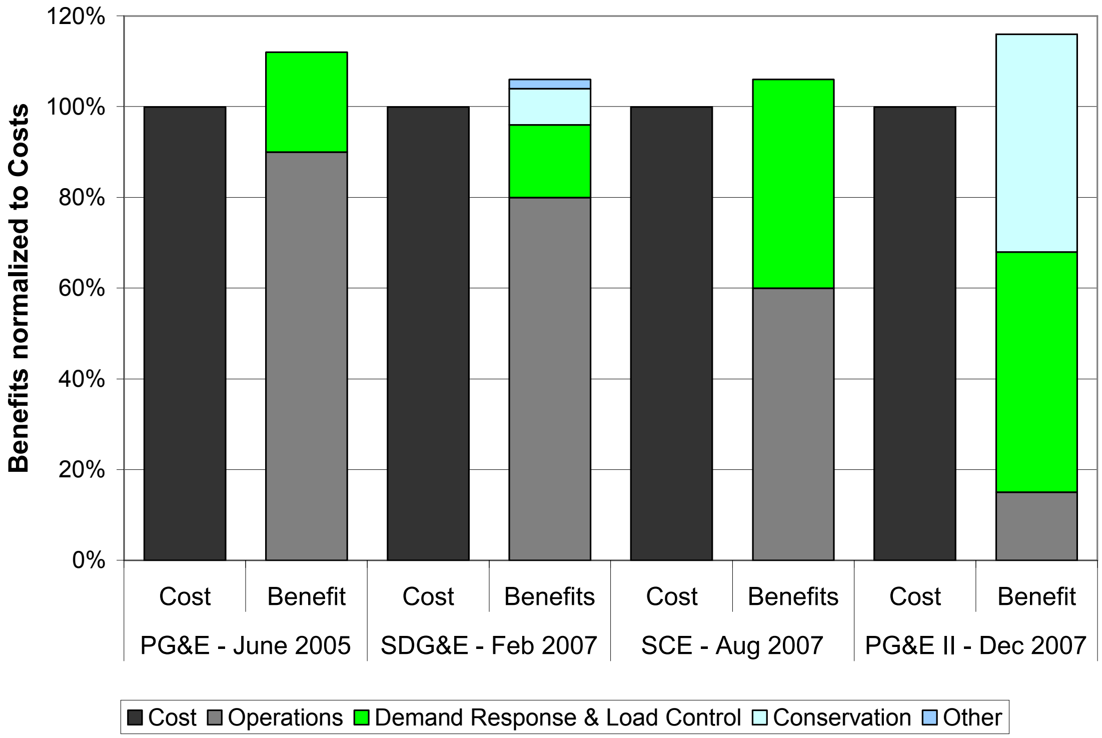
[33] *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies - Part 2*, Energy Central (June 18, 2007). http://topics.energycentral.com/centers/datamanage/view/detail.cfm?aid=1495.
[34] Id
[35] Press release, Itron, Gas & Electric Chooses Itron OpenWay® for Smart Meter Deployment (July 30, 2008). http://www.itron.com/pages/news_press_individual.asp?id=itr_016717.xml.

**Figure 6: Comparison of AMI Costs and Benefits**[36]




Dynamic Pricing and Critical Peak Pricing (CPP)
Large commercial and industrial customers with maximum load greater than 500 kW have been on mandatory TOU rates since at least the early 1980's, depending on the size of the customer.[37] As noted earlier, in 2001, the California Legislature appropriated $35 million to be used by the CEC "to provide time-of-use or real time meters for customers whose usage is greater than 200 kilowatts."[38]

Currently, all the commercial and industrial (C&I) customers above 200kW are on TOU rates and also have the option to sign up for a voluntary CPP rate and a large number of demand response programs. Real time pricing rates are not currently available to large C&I customers.

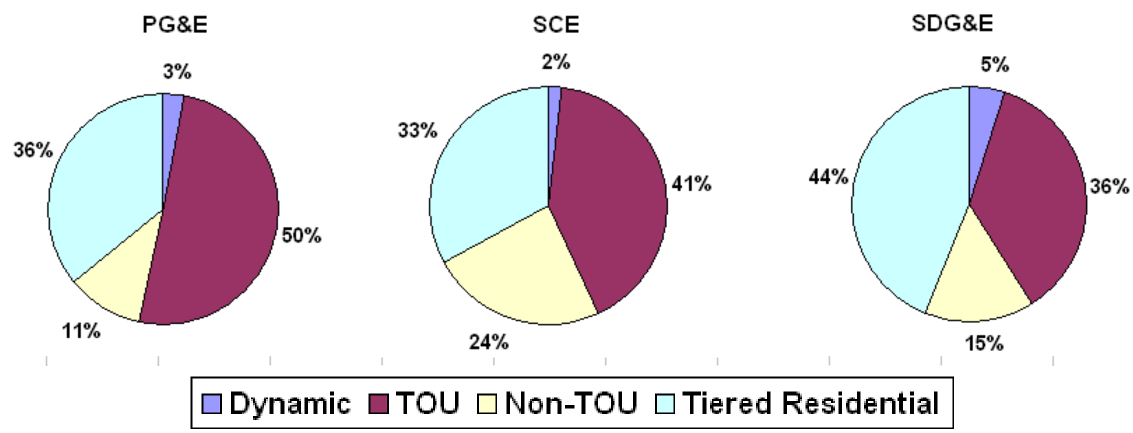
[36] Source: "Advanced Metering Infrastructure: The Regulatory Context." Demand Response/AMI Presentation to EDF by Tom Roberts, CPUC. June 23, 2008

[37] *See* D.85559, 1976 Cal. PUC LEXIS 1308 (Cal. PUC 1976) (ordered three major utilities to implement mandatory TOU for customers with demands greater than 500 kW); D.86632, 1976 Cal. PUC LEXIS 931 (Cal. PUC 1976) (approved mandatory TOU rates for PG&E customers with maximum load greater than 4,000 kW); D.90588, 1979 Cal. PUC LEXIS 772 (Cal. PUC 1979) (approved mandatory TOU rates for PG&E customers with maximum load between 1,000 kW and 4,000 kW); D.92553, 1980 Cal. PUC LEXIS 1279 (Cal. PUC 1980) (approved mandatory TOU rates for PG&E customers with maximum load between 500 kW and 1,000 kW).

[38] Assembly Bill 1X 29 from the 2001-2002 First Extraordinary Session, Section 14(d)(4)(B).

However, a large number of the small to medium C&I and residential customers are not on TOU or dynamic rates. As discussed above, AB1X effectively prohibits default dynamic rates for residential customers and prevents rate increases for the first two tiers in residential rates. This will continue to keep average retail prices relatively low for about 60% of residential customers that have usage below the Tier 3 threshold. For an overall breakdown of each utility's customers and the type of rate they are served under, see Figure 7 below.[39]

**Figure 7: MWh Sales by Rate Type by IOU**




One of the main goals for demand response under the Energy Action Plan is to increase the ability of customers to participate in dynamic pricing and the CPUC has made steady progress in moving towards this goal. SDG&E has already implemented default CPP for commercial and industrial customers above 200kW.[40] One stakeholder indicated that the opt-out rate was around 50%, which was less than feared by some. On the other hand, there were no calls on the default CPP rates by SDG&E in 2008, so opt-out rates may rise with increased calls. SDG&E will roll out their default CPP rates to non-residential bundled customers with loads greater than 20 kW as Smart Meters are installed across their service territory.[41]

Default CPP rates for SCE's larger customers will be considered before the CPUC during Summer 2009 and customers with peak demands less than 200 kW will be offered CPP as an optional tariff after installation of their SmartConnect™ meters.[42] On February 27, 2009, PG&E filed its 2009 Rate Design Window Application with the CPUC. The application was submitted to comply with CPUC Decision 08-07-045 which ordered that PG&E propose dynamic pricing rates. These rates would go into effect beginning May 1, 2010 starting with large commercial and industrial customers with electric load that is greater or equal to 200 kW. Agriculture customers and all other customers will default to dynamic pricing rates on February 1, 2011 or one year after the

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[39] CPUC: Bruce Kaneshiro presentation June 23, 2008

[40] D.06-05-016, Ordering Paragraph 2.

[41] Pursuant to SDG&E's 2008 General Rate Case, A. 07-01-047, which was adoptd by the CPUC in D. 08-02-034.

[42] 2009-2011 Demand Response Program Filings. CPUC Application 08-06-001. Filed June 2, 2008.

installation of their SmartMeter™ device. The CPUC also directed PG&E to file default dynamic rates for residential customers within one year after the AB1X rate cap is lifted. Customers will have the option to opt-out of the default dynamic rates, and if the customer is participating in a demand response program, it is proposed that they not be forced onto the dynamic pricing tariff. The CPUC has asked stakeholders to comment on whether the proposed schedule for full implementation of default dynamic rates for PG&E is not also appropriate for the other utilities.

The table below shows the timeline for PG&E's dynamic pricing rate structure by customer class. Each year shows the default rate. Real time pricing (RTP) is an optional rate.[43]

**Table 13: Commercial & Industrial (C&I) Default Rates - Proposed Timetable for PG&E**

| Customer Class | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| **Large C&I (>=200kW)** | TOU | TOU | TOU/CPP | TOU/CPP (RTP) | TOU/CPP (RTP) |
| **Medium C&I (<200kW and >=20kW)** | Flat | Flat | TOU/CPP | TOU/CPP (RTP) | TOU/CPP (RTP) |
| **Small Commercial (<20kW)** | Flat | Flat | Flat | TOU/CPP (RTP) | TOU/CPP (RTP) |
| **Residential** | Tiered Flat (TOU, CPP) | Tiered Flat (TOU, CPP) | Tiered Flat/PTR (TOU, CPP) | Tiered Flat/PTR (TOU, CPP, RTP) | Tiered Flat/PTR (TOU, CPP, RTP) |

<u>CAISO's Market Redesign and Technology Upgrade</u>

Under MRTU, the wholesale market will provide DR resources with comparable treatment and the enhanced operating flexibility afforded supply-side resources. CAISO is developing a new wholesale demand response product, called Proxy Demand Resource (PDR) and is refining its existing Participating Load program to be fully compatible with its new market design. The CAISO launched a limited Participating Load product with MRTU on March 31, 2009, and, with significant stakeholders involvement, is developing the PDR product that will facilitate bids of aggregated DR programs into the MRTU market by Curtailment Service Providers (CSPs). Refinements to it existing Participating Load program and, if approved, the proposed PDR product are targeted to be implemented around May 2010.[44]

<u>CAISO's DR365 Laboratory</u>

The DR365 Lab is a CAISO-sponsored demonstration project which opened in December 2007. The lab tests automation technology that helps consumers make set changes in their electricity use and reduce the strain on the grid while reducing costs for the consumer. The lab is named DR365 because the CAISO wants to expand the

[43] TOU = Time of Use, CPP = Critical Peak Pricing, TOU/CPP = Critical peak pricing with time-of-use during non-CPP periods; RTP = Real Time Pricing, PTR = Peak Time Rebate

[44] CAISO Demand Response Strategic Initiative Program Overview Presentation. February 16, 2009.

traditional vision of demand response as a summer-peak resource to a year-round capable resource that can assist California with integrating greater amounts of intermittent renewable resources.

Among other things, the lab strives to demonstrate technologies that show how load curtailments could be aggregated together and automated to participate as a resource in the CAISO markets. The automation technology provides better certainty of the load curtailment and, CAISO believes, helps to enhance the reliability of demand response resources.[45]

2009 CAISO Participating Load Pilot Projects

The CAISO is in the process of developing three Participating Load pilot projects that will be operational by summer 2009 with the goal of providing non-spinning reserves from a cross-section of end-use load types. SDG&E will demonstrate a commercial aggregation project with end users whose load consumption is greater than 20 kW. SCE will demonstrate an aggregation of 3,200 residential AC cycling units and PG&E will conduct a pilot test focusing on large commercial or industrial customers. The objectives are to understand the performance and reliability of different participating load resource types, explore telemetry requirements and alternatives, identify and address operational issues, while building confidence around non-generation resources as being able to provide a high quality reliability service.

Identification and Resolution of Direct Participation Business Issues (Working Groups)

The CAISO is launching a structured working group process to discuss and resolve the issues around demand response functioning as a direct participation resource under the PDR product line in the CAISO markets. The business issue resolution process will focus on the following seven categories:

- **Qualification**: program definition, participant and resource qualification)
- **Registration:** resource characteristics, enrollment, transfers, testing and auditing)
- **Scheduling:** system and resource forecasting, resource scheduling and bidding)
- **Notifications:** market schedules and awards, RT dispatch, outages)
- **Metering and telemetry:** data availability, exchange, type and granularity)
- **Settlement:** calculation of load changes, calculation of credits and charges)
- **Performance and compliance evaluation**:[46] resource, participant, program, and system performance evaluation, compliance monitoring

Additional details about this business issues resolution framework can be found in Appendix F.

CPUC DR OIR (R. 07-01-041)

The CPUC initiated a rulemaking proceeding in January 2007 to investigate several issues related to demand response. Phase 1 of the proceeding began in spring of 2007

[45] http://www.caiso.com/1ca9/1ca98d4d13d10.pdf

[46] CAISO Demand Response Strategic Initiative Program Overview Presentation. February 16, 2009.

and focused on the development of protocols and methodologies related to cost-effectiveness evaluation and load impact estimation. Phase 2 focuses on establishing new DR goals. Phase 1 resulted in the filing of a joint framework proposal for cost-effectiveness calculations. This "consensus framework" represented agreement by the various parties on approaches to some of the major cost-effectiveness issues previously in dispute. The consensus framework broadly described the principles and goals of a cost-effectiveness methodology, but left several issues unresolved, which parties agreed would need to be deferred to a future proceeding. CPUC staff developed a more detailed framework proposal (the "Staff Framework"), based on the consensus framework, that addressed several of the unresolved issues. The development of a more detailed cost-effectiveness methodology is still on-going.

In April 2008, CPUC issued a decision adopting load impact protocols for IOU DR programs (D 08-04-050). The adopted protocols define minimum data outputs required to estimate DR impacts, and statistical measures to assist in determining the accuracy of these impact estimates. The protocols are intended to be flexible enough to allow load impact evaluators to choose methodologies that are both feasible for and suitable to the particular type of DR activity.

<u>CPUC Resource Adequacy (CPUC R. 05-12-013 and R.08-01-025)</u>
The CPUC adopted a Resource Adequacy (RA) policy framework in 2004 in order to ensure the reliability of electric service in California. The CPUC established RA obligations applicable to all Load Serving Entities (LSEs) within the CPUC's jurisdiction, including investor owned utilities, energy service providers (ESPs), and community choice aggregators (CCAs). The RA requirements promote infrastructure investment by requiring that LSEs procure resources so that capacity is available to the CAISO when and where needed. The RA program now contains two distinct requirements: System RA Filings (submitted monthly) and Local RA Filings (submitted annually).

Each LSE is required to demonstrate that they have procured sufficient capacity resources, including a 15% Planning Reserve Margin (PRM) that will be needed to serve its aggregate system load on a monthly basis. In addition, each LSE is required to file with the Commission documentation demonstrating procurement of sufficient Local RA resources to meet their RA obligations in transmission-constrained Local Capacity Areas. The CPUC is also considering Long-Term RA Program Development including capacity market design proposals (i.e. bilateral vs. centralized) in R. 05-12-013.

In April 2008, the CPUC opened Rulemaking R.08-04-012 initiating a study to recommend a level of reliability that seeks to ensure that sufficient resources are made available to meet specified probabilistic reliability levels. The PRM Study will be performed by the CAISO and General Electric (GE) using the Multi Area Reliability Simulation (MARS) model. A final decision regarding the PRM for 2010 and beyond is expected in the Fall 2009. The probabilistic methodology used by GE MARS model is meant to consider load and resource uncertainties, including the availability and performance of intermittent and energy-limited resources, transmission interface constraints, relationships between transmission and generation facilities, and analysis of various case scenarios that examine impacts of changes due to present and future generation, load growth and potential transmission development.

CPUC Smart Grid OIR (R. 08-12-009)

The CPUC Smart Grid Proceedings will provide an avenue for a further and comprehensive investigation of technology and infrastructure issues. The proceeding was kicked-off with a Pre-Hearing Conference in March 2009 and a widely attended Symposium on April 21st. A specific scope and schedule for the proceeding had not been defined at the time this report was written.

# 7. BARRIERS

Following the literature review and stakeholder interviews, the project team compiled and summarized the feedback on the myriad barriers (as well as issues) identified. Many stakeholders raised similar barriers and issues using different language and the project team collapsed these to their common root. In order to provide some structure to the results, the research team grouped barriers into categories. Finally, in describing the barriers, in part based on feedback from stakeholders, the consulting team differentiated challenges between 'barriers' and 'critical issues'. For each category below, the barriers are addressed first, followed by the critical issues associated with that category.

Finally, it is important to note that the goal of the project team was to report back on the stakeholders' positions regarding what they deemed to be barriers, not to determine whether a particular position had more merit than another. Therefore, the barriers and issues identified are useful in understanding the current range of perspectives on DR in California, but not necessarily whether they are factual.

The resulting categories are:

**Market barriers and critical issues** – The market barrier category includes those challenges that surround participation of demand response in the capacity, energy, and ancillary services markets in California. The current DR environment in California has been shaped in large part by the three decades of load management and DR experience which the state's utilities, customers and regulators have collectively developed and nurtured. That experience can be viewed as a blessing (in terms of customer awareness, system operator confidence in the reliability-based programs ability to deliver MWs, regulatory and legislative familiarity with the issues when addressing demand constraints, etc.). It can also be viewed as a curse in that the historical experience has also brought with it a sense of program ownership, incentive level entitlement, program design familiarity, and other factors among the various key stakeholders that impinge on moving rapidly in ways that are unfamiliar.

**Regulatory barriers and critical issues** – This category of barriers includes the challenges from meshing the regulatory perspectives of various state agencies, as well as alignment with federal DR policy. The California regulatory environment is a well-established and somewhat unique model stretching back to the legislative creation of the California Energy Commission in the 1970s, and their mandate to oversee load management standards. In California, there are three state agencies interested and involved in demand response with their own authorities and functions in addition to the CAISO (i.e., CPUC, CEC, and the California Air Resources Board). In addition, the California Legislature has been active in passing statutes with significant DR implications, such as AB1X (see the dynamic pricing discussion in Section 6).[47]

**Customer Participation barriers and critical issues** – The customer participation barriers and critical issues category includes challenges that push customers away from participating in DR in California, be it via a retail program, or the CAISO wholesale energy market. Some of these are pragmatic (i.e., too little potential financial reward to justify the level of effort involved in taking DR actions), some are based on the

[47] California State Assembly Bill 1X enacted in 2001.

customer's business model (i.e., energy costs make up a small percent of their operating costs, and in some cases are pass-through costs, and so warrant relatively little attention), and some are a perceived lack of comfort with the demand response concept. While customers in California understand ('get') energy efficiency, the same generalization cannot be made when talking about demand response.

**Infrastructure and Technology barriers and critical issues** – this category focuses on those barriers identified by the stakeholders that are more related to the infrastructure required to implement DR. The utilities and CSPs under contract to them have had some success with encouraging larger customers to install automatic DR communicating and switching devices, and more recent programs have penetrated residential and small commercial AC markets. The three IOU's are also implementing AMI with full installation anticipated by 2012.

**Operations and Settlement barriers and critical issues** – this set of barriers and issues relate to the operations and the back-office processes necessary to support DR. Many of the challenges are developmental in nature as the operational and settlement protocols and systems continue to evolve and DR increasingly participates in the CAISO markets. The evolution involves moving from a model built upon proven and well understood generation technologies, to one where customers' behavior and decision-making patterns play a key role in determining the quantity and quality of the resource to be provided.

The key barriers and critical issues affecting the California DR market as identified through the literature review and the stakeholder interviews are described below. However, while the barriers and issues have been segmented in order to structure the discussion, it will become apparent, in some cases, how interwoven they can be. Also note that the barriers are set in bold print, while the critical issues are differentiated by being underlined.

## 7.1. Market Barriers and Critical Issues

### 7.1.1. Barriers

**MB.1 Resource Adequacy (RA) capacity payments are elusive for DR Resources that would participate in the CAISO markets outside of a retail DR program**

The CPUC has implemented RA requirements to ensure the procurement of sufficient capacity resources by LSEs under its jurisdiction (See Section 6.). The CPUC has also ruled that dispatchable DR programs should count towards meeting RA requirements. DR resources therefore have a value to the LSE to the extent they reduce the amount of capacity the LSE must purchase to meet RA requirements. At this time, however, there is no mechanism or market that provides capacity revenues directly to the DR customer or Curtailment Service Provider. The only capacity payments for DR resources currently available in California are those provided by the regulatory driven programs managed by the IOUs. If such capacity payments are not available for DR resources, many stakeholders feel there is little or no incentive for customers to participate directly in CAISO markets given the variety and level of capacity incentives provided by the IOU through the retail DR programs.

While the CPUC has set forth a policy of counting all DR resources towards RA requirements, the CAISO, as the system operator, has a different perspective. The CAISO has not agreed that DR that can be called only during system emergencies should count towards satisfying the planning reserve margin. Nor does the CAISO understand if the load impact protocols adopted by the CPUC, which is a planning standard, are the most appropriate for determining DR resource capacity availability in its operational timelines. Given the wide variety of DR program design parameters associated with the length of the notification period, maximum duration and maximum call frequency, the CAISO believes more careful analysis is needed to determine what types of DR programs should and should not count as RA capacity from an operational perspective, and what, if any, adjustments should be made to translate enrolled MW in various DR programs to reliable impact estimates.

The CAISO did offer one clarification regarding the issue of DR qualifying as RA capacity. It is the local regulatory authority (i.e., the CPUC, city council, utility board, etc.) that sets the rules for how capacity qualifies as RA. A resource that qualifies as RA capacity does have a must offer obligation under the CAISO tariff. However, demand response resources are exempted from the must offer obligation since they are considered use-limited resources.

Under current CAISO market rules, load-serving entities must schedule 95% of their load in the Day-ahead market, and the Resource Adequacy resources have a must offer obligation which ensures RA capacity resources are available when and where needed. However, stakeholders saw these two market rules as potentially limiting the amount of DR that will show up in the wholesale market by reducing any price volatility in energy prices that would entice demand response. The expressed concern was that CSPs not already locked into a retail bilateral demand response contract with a utility might shy away from directly participating demand response resources in the CAISO markets as the market may not provide sufficient revenue to make DR a viable business.

In addition, since California does not operate a centralized capacity market, RA capacity that a LSE does not self-provide, must be procured through bilateral arrangements. As a result, the wholesale value of RA capacity is not transparent. Therefore, it can be challenging for a CSP to know if there is a viable wholesale DR business in California given RA capacity is likely the most significant component of the overall DR revenue stream.

### MB.2 Lack of a transparent, forward capacity market for direct participation DR resources

It is also important to note the disconnect between the CAISO market structure built around short term procurement and customers expressed interest and need for greater confidence in revenue and/or cost saving over a longer term (i.e., three to five years) in order to justify the capital investment necessary to establish a viable business built on demand response resources. The historic approach in California has been to provide retail programs either through the utilities or CSPs, many of which generally have capacity payment-oriented program designs linked to the 3 year funding cycles approved by the CPUC. In addition, incentive monies, including Technical Assistance/Technical Incentive (TA/TI)[48] funding has been made available by the CPUC to help offset the customer's upfront capital costs. When considering direct participation of DR in the CAISO markets, given there is not a centralized capacity market, there is no clear way to assure regular capacity payments, or a mechanism to provide incentive monies, to promote more automated demand response capability.

Early on in the CPUC RA proceeding there was discussion regarding the pros and cons of creating a capacity market in California, and the various forms such a market might take (see CPUC Staff Capacity Market White Paper, September 23, 2005). The CAISO has, as a participant in the RA proceedings, advocated for the development of a centralized capacity market. Although the CPUC is in the process of establishing a definition for a tradable capacity product, the CPUC has not yet determined whether or not it supports the development of a Capacity Market. While many stakeholders feel that developing a forward capacity market is critical to the increased participation of DR resources in the CAISO markets, the prospects for such a market in the near term are uncertain at best.

### MB.3 Regulation and spinning reserve markets are precluded by WECC rules

One area that the CSPs and IOUs agreed would be of interest to them relative to matching the DR resource capabilities to a CAISO product line involves the Ancillary Services (AS) market. Here, stakeholders see potential value and a wholesale revenue stream, but are thwarted by the current WECC requirement that AS can only be provided by generation-based technologies. While there was a high level of interest in seeing the AS requirements modified, stakeholders were split on the extent to which they expect load to participate. Some felt participation would be limited to a few large customers, while others saw the potential for aggregated programs (e.g. automatic AC cycling) to participate in AS markets as well.

In terms of regulation resources, and more specifically the AS market compliance requirements as currently held by WECC, the stakeholders felt that the wholesale capacity market rules need to be revised so as not to be biased for or against any

[48] These CPUC approved incentive monies are designed to help customers be more receptive to DR opportunities by first providing partial funding for engineering technical assistance charged with identifying DR opportunities, and second by partially funding through the technical incentive portion of the program the capital costs associated with making the enabling upgrade for the customer.

particular resource type, but rather be based solely on the resource's capability and performance.

In addition, some stakeholder customer advocates noted that while there are customers who may not be able to commit to curtailing load in compliance with program operational rules based on a one year or six month contractual term, they may be able to participate in the AS markets, which do not require a long-term contractual commitment.

### MB.4 Customers accustomed to existing investor-owned utility programs

As noted above, California has a long history of offering reliability-based DR programs to electricity customers. These include the legacy AC direct load control programs in the mass market sectors, as well the interruptible and curtailable rate tariffs that have basically been in place since post-PURPA in the late 1970s. The state's track record in offering DR programs is highlighted in the tables presented in an earlier section.

There is a significant quantity of reliability-based DR funded through the CPUC approved retail DR programs and tariffs. These programs have key advantages from a customer acceptance standpoint:

- customers understand the rationale associated with the emergency-based triggers in terms of helping to avoid rotating outages or black-outs;
- customers have grown accustomed to the capacity payment revenue stream aspect of the programs' designs, both in terms of the regularity of receiving payment, as well the amount of the capacity payments; and
- there is the perception among customers that the likelihood of being called to curtail their load is relatively small within a season or from year to year. Some believe that this is in part based on the perception that the utilities historically viewed the large interruptible/curtailable rate options as more of an economic development or customer retention tool rather than as a regular load relief resource.

This is a barrier in that customers who are accustomed to such longstanding programs based on regular capacity payments and limited DR curtailments are not generally inclined to voluntarily switch over to an economic-triggered energy only product with potentially greater numbers of calls. Furthermore, as discussed under MB.1 and MB.2, most stakeholders saw a limited incentive for customers to favor direct participation over IOU-managed programs, absent a readily accessible capacity payment.

## *7.1.2. Critical Issues*

### MI.1 Attributes of existing retail programs are poorly aligned with CAISO markets

In addition to the market barriers identified by stakeholders, a number of stakeholders also raised several 'critical issues' on the non-financial aspects of the existing programs that retail customers prefer but that do not mesh well with a straight wholesale economic transaction. As was noted above, the economic triggers envisioned by CAISO in their model of DR resources being available year round, where possible, may result in more frequent operations based on price fluctuations. According to the stakeholders, this will likely result in more requests for DR load curtailments. This creates problems for the DR customer base in terms of the following attributes:

Customers like to see limited operations due to the impact that complying with curtailment requests can have on their businesses. While Auto DR technologies and sophisticated (and well-calibrated) energy management systems can help automate the customers' programmed curtailment to price signals, they are currently not the norm. Therefore, when considering economically-triggered DR, customers weigh the hassle and risk factors against the potential, though far from assured, financial benefit.

One of the non-financial attributes of reliability-based or emergency-triggered DR programs where customers see added value is the perceived clear link between curtailing load in order to fulfill the role of "good corporate citizen." With such programs, the customers can polish their corporate image by helping to avoid rotating outages, thereby benefiting themselves as well as their societal neighbors. The "recognition" benefit can also be seen within a corporate organization where the DR implementer (i.e., Director of Facilities) is rewarded by corporate management for pursuing DR's "good corporate citizen" moniker. Switching to price responsive DR product designs does not carry the same cache, both in the minds of many of the stakeholders, as well as articulated by business customers here in California.

According to the stakeholders, customers (and the utility LSEs that currently implement the DR programs) favor triggers that are predictable and transparent, thereby better enabling the parties to assess the DR business model being marketed to them. Complicated mechanisms that are based on electric wholesale market transactions are viewed as clouding the offer, and likely pushing customers away from easily assessing the risk/reward equation. A counter to this point made by some is that the actual customers, in most cases, will not have to come to grips with the wholesale mechanisms as their CSPs will provide them with the information they need in order to meet their DR expectations. While there is likely truth in that, it is interesting to note that the CSPs shared a frustration that they have with currently trying to explain to customers how all the retail and wholesale pieces and transactions fit together.

The current plate of retail DR programs almost exclusively limit curtailments to between May 1$^{st}$ to October 31$^{st}$, and often limit curtailment to set blocks of time in the afternoon – early evening hours. Again, participants have become accustomed to this longstanding program design feature, although many do recall the 2001 energy crisis when the state's Energy Emergency Plan (EEP) triggering mechanisms were utilized in the winter months, for repeat consecutive days, and for stretches of consecutive hours that broached the interruptible tariff's contract terms. Promoting economically triggered DR that will be in play across the annual 8,760 hours will, according to many of the stakeholders, push customers away from participating in DR.

This position is somewhat further complicated in the California market in that the CPUC is moving the utilities towards offering to their customers with demand over 200 kW a default dynamic pricing tariff (with an opt out if the customer chooses a DR program), beginning in 2010. While the retail default pricing tariff will look akin to critical peak pricing, it will not necessarily be linked to the price level, frequency of high prices, or other attributes of wholesale prices in the CAISO market.

MI.2 CSPs precluded from direct participation without the proposed PDR product.

Stakeholders worked hard to collectively create an alternative approach to providing access for direct participation of DR in the CAISO markets. The stakeholder working group used as a starting point, the CAISO's initial straw proposal for the Proxy Demand Resource (PDR) product, which was initially viewed by most stakeholders as having critical flaws. Working together, the group developed an alternative approach and proposal which not only met the needs that CAISO had described, but also would allow the CSPs to directly participate in the CAISO wholesale market without adversely affecting the LSEs. It also allows the utilities to better manage their LSE responsibilities, as well as provide DR resources.

The significant concern expressed by more than one utility is that if PDR were to be rejected by FERC, there would be no means for retail DR programs to participate in CAISO markets. However, stakeholders were quick to state that this report should emphasize the role that PDR plays in facilitating direct participation, but not be quick to count barriers or issues as resolved just because FERC approves the PDR product.

Many stakeholders thought the PDR stakeholder process was working well, with a small but productive group of dedicated participants, and believe the May 2010 target date is challenging but achievable. Still, some stakeholders expressed frustration that the process is rushing to meet FERC deadlines when a somewhat longer but more coordinated effort would produce better and more realistic results for California. Others pointed out that the current PDR proposal was developed by the stakeholders in response to a CAISO proposal, and that the stakeholders had to push strongly to get what they viewed as essential changes made to the original CAISO design.

MI.3 IOUs will likely remain a key player in offering DR to the customer base, and take direction from the CPUC and CEC, not CAISO

In terms of Demand Response in California, stakeholders felt the California Public Utilities Commission is in the "driver's seat" of DR in California since they authorize the funding and the program designs which the utilities (and CSPs) implement by recruiting participants and operating the DR resources. This aspect of the DR money trail is not likely to change soon, especially when considering that there are capacity payments associated with the retail programs offered. This holds true for both the DR offerings put in the field by the IOUs directly, as well as for the offerings being marketed by the CSPs through their CPUC-approved bilateral contracts with the utilities. These contracts are currently set to run (in some cases) through 2012, and then be eligible for extensions. It is unlikely that California will have a forward capacity market in place anytime soon, so it is reasonable to assume that the retail DR resources will remain in much the same structure as has been the case to date.

The impact on direct participation of default dynamic pricing is unknown at this point. One variable that may impact this is how the introduction of the CPUC-mandated PG&E default dynamic pricing (with opt out provisions for those customers going onto DR programs) for customers over 200 kW will impact DR program enrollment.

The question of dual-participation and double payment has been raised in CPUC proceedings and is considered a critical issue by some stakeholders. Will customers on default dynamic or CPP tariffs be permitted to also participate directly in CAISO markets and if so, how will ratepayers be protected from over paying for DR? If not, will implementation of such default tariff options reduce the pool of potential direct participants?

All of this points to the likely continuation of the status quo concerning how retail DR is approved, offered and implemented in California. The status quo is likely to continue until such time as there is a better linkage between retail DR programs and the wholesale market design and until the CPUC determines how much and through what vehicles DR is to be harvested. In terms of increased DR direct participation, there is a concern that it will likely be somewhat hampered until the DR bilateral contracts held by the CSPs expire and a forward capacity market develops.

### MI.4 Various DR market vision perspectives among stakeholders

In talking with the various stakeholders and across the stakeholder segments, it was interesting to note the somewhat anticipated schism between the subsets of stakeholders when it came to their respective DR visions. In thinking about what the future of DR should look like in California, there were those that felt strongly that the retail utility and CSP bilateral contract model works well and should be retained, albeit with some adjustments. Another subset supported the movement espoused in some regulatory circles to move to a wholesale centralized forward capacity market structure, while others believe the capacity market should be eliminated and transition to energy only markets. This lack of consensus and vision, when matched up with the push and pull of whether the CPUC's or FERC's marching orders should be viewed as paramount, allows all parties to continue to lobby for their perspective, rather than getting in line behind a common (and somewhat fleshed out) vision of where DR is headed in California. Not having this clear consensus around a DR vision and roadmap is a critical issue.

A good example of how divergent the perspectives can be is drawn from the discussions across the interviews in relation to bilateral markets:

- Some object to the lack of transparency and alleged high transaction costs associated with bilateral RA contracts between utilities and CSPs;
- Others feel bilateral contracts provide greater flexibility to accommodate different types of load and participants while providing the CSP the flexibility to link customers who individually have constraints, but as a whole, provide a more robust resource;
- Others claim that if a centralized capacity market is integrated into the wholesale market design, allegedly the experience in eastern markets show that costs to users may increase.

Clearly, California stakeholders are far from having a consensus market vision as to DR's role as an energy resource in the future.

## 7.2. Regulatory Barriers and Critical Issues

### *7.2.1. Barriers*

#### <u>RB.1 Fundamental policy differences between the wholesale (FERC/WECC/CAISO) and retail (State Legislature/CEC/CPUC) perspectives</u>

FERC and the CPUC are viewed by stakeholders as having fundamentally different policy goals, which presents a barrier to direct participation in wholesale markets managed by CAISO and regulated by FERC. Tension between federal and state regulatory approaches is not unique to California. California, however, has a long history of independence and leadership on environmental and energy issues. On myriad issues, California has established goals and regulations that are more stringent or aggressive than under Federal legislation.

With respect to DR, there is a basic difference in the approach to promoting and valuing DR. FERC's focus is seen as promoting competitive and transparent wholesale markets with the aim of reducing energy prices through healthy competition. FERC seeks to include as many of the procurement and operational decisions as is practical in those markets, minimizing the transactions that occur outside the view of market participants. FERC's directive in Order 719 to allow DR to participate in wholesale markets on a comparable basis with generation appears to reflect this policy.

The CPUC is seen as not being as strong a proponent as FERC in terms of competitive energy markets. California policy-makers at the state agencies and government see the need for long-term planning in addressing multiple policy goals that are not achieved through short-term markets operated by CAISO. With this view, the California Legislature and the CPUC have embraced a stronger role for regulation to shape and direct energy policies within the state. Evidence of the regulatory-driven approach is reflected in the long history of ratepayer-funded energy efficiency programs in California, Title 24 building standards and the Energy Action Plan's (EAP) loading order that expresses a preference for energy efficiency and demand response over conventional resources to meet load growth.

Several stakeholders emphasized that the CPUC has primary authority for long-term planning and reliability. The CAISO has a central role in operating the transmission system and performing planning studies to identify when and where new resources are needed to maintain system reliability. Those resources, however, are developed and procured by the California utilities under the oversight of the CPUC. The CPUC also retains a central role in defining the RA standards that the utilities must meet in the procurement of capacity resources which are then used by the CAISO to maintain the reliability of the grid. The CPUC is seen as continuing to view long-term resource planning and procurement oversight as its responsibility. The political reality is that any customer dissatisfaction regarding reliability or rolling black outs will be directed largely at the utilities, the CPUC and the state legislature, not FERC or the CAISO. As a result, the belief is that the CPUC is unlikely to cede authority in this area, particularly given the state's experience with the energy crisis of 2000-2001.

The California Legislature is also an active player in the energy policy arena; state statutes such as AB 1X are in place that have implications on how and when dynamic pricing/DR will be more impactful. The CEC has opened regulatory proceedings to review their Load Management standards which remain in their purview, having been legislatively promulgated in the 1970s; these have no readily apparent linkage to the CAISO wholesale markets, other than CAISO staff participating in the hearings.

Stakeholders also expressed some frustration at FERC timelines and requirements with respect to DR that are imposed with apparent little regard to California's ongoing DR proceedings or political landscape. Many felt they were being required to 'jump through hoops' to meet FERC deadlines that are premature given the status of CPUC proceedings, and that better alignment was necessary. In the words of one stakeholder, FERC directives for a 'timely' response does not necessarily mean 'quick' when some coordination with state efforts would produce a better designed and more effective policy. DR is heavily intertwined with other issues such as long-term resource planning, Resource Adequacy, GHG policy, the return of Direct Access and default dynamic/ CPP rates. Some stakeholders felt these issues will only be resolved over time and that rushing to implement direct participation in California is counter productive. Other stakeholders express a desire for CAISO to be more proactive at identifying inconsistencies between FERC and California mandates and engaging California agencies in resolving them.

### RB.2 Regulatory driven programs limit growth opportunity for CSPs

Under the direction of the CPUC, IOU's have contracted with CSPs to market and implement some of their DR programs. It may be possible for ESPs to enroll their direct access customers in DR programs. For the sake of simplicity, the term CSP will be used to refer to all non-utility DR providers.

When compared to the utilities, many parties perceive CSPs to be in a better position to design and market innovative DR programs. As private companies in a competitive market, CSPs may have a stronger incentive to attract and retain new customers. CSPs are viewed as more nimble, likely to take risks and able to develop innovative marketing strategies. CSPs are also seen as better suited to tailoring programs to meet the needs of niche markets.

Beyond the potential for CSPs to expand and increase their market share, and therefore DR participation, the perceived advantages of CSPs may be somewhat limited in the current market structure since they are operating under utility-sponsored bilateral contracts. Many stakeholders viewed these constraints as posing a barrier to the growth of DR in general and to direct participation of DR in CAISO markets in particular. While the CPUC has directed the utilities to integrate their programs with wholesale markets, the mechanisms or financial incentives for doing so have not yet been established. CSPs on the other hand, would have a strong financial incentive to earn increased revenues by bidding their programs into the wholesale markets when a) customer preferences allow them to do so, and b) wholesale markets exist that provide sufficient revenue.

Many stakeholders believe that a primary problem in the California market is that the CSPs are both a customer of and a competitor to the utilities. As long as they are reliant on utilities for a significant portion of their revenues in the state, it is unlikely that they will feel free to compete aggressively for DR customers. Furthermore, the utilities are able to offer multi-year capacity payments in their contracts with CSPs, which the current market structure in California does not offer.

Utilities also are seen by some stakeholders as having significant competitive advantages relative to CSPs. As a monopoly, they are seen as having a great deal of sway in the market. Although the utilities are regulated, they are also seen as having a good deal of access to and influence with CPUC commissioners and staff. Some stakeholders cited instances where they saw a utility as being able to hide the devil in the details and operate beneath the radar of regulators and intervenors. Stakeholders also shared their perspective that utilities have larger staffs with a greater capacity to participate in the myriad ongoing regulatory proceedings, comply with regulatory reporting requirements, and to absorb the overhead costs associated with DR programs.

Finally, stakeholders, and not just CSPs, raised the issue of compliance and transaction costs related to many of the barriers in the report. Cumulatively, transaction costs pose a barrier to CSPs (as well as other stakeholders) and place them at a competitive disadvantage with larger utilities. Costs raised as critical issues or potential barriers include installing telemetry, metering and software systems, negotiating multiple bilateral contracts, retaining consultants, scheduling coordinators and back-office solution providers performing multiple impact and baseline calculations according to different methodologies, and complying with CAISO, CPUC and utility documentation and reporting requirements.

### *7.2.2. Critical Issues*

RI.1 Program value may not be fully recovered in wholesale market, limiting incentives for direct participation

As has been emphasized above, customers in California have become accustomed to the incentive payments available under existing DR programs. There is no guarantee that the wholesale market would provide comparable revenue. In fact, many stakeholders express an expectation that the revenues available through wholesale energy markets would be significantly lower. Stakeholders were particularly concerned that currently available incentives for the regulatory-driven DR programs include forward capacity-based payments, which are not currently available through the CAISO. A related issue is that California's DR goals reflect multiple policy objectives, many of which are not readily monetized in a competitive market. Furthermore, the cost-effectiveness criteria used by the CPUC and utilities in evaluating their DR programs will not necessarily produce a valuation that is consistent with the wholesale market. For example, cost-effectiveness criteria often benchmark retail DR programs against the cost of a new combustion turbine (CT). However, in a market with sufficient generating resources, a market clearing price for capacity or resource adequacy might be significantly less than the cost of a new CT.

Some stakeholders also expressed a fear that there remain significant upfront costs in developing and deploying enabling technology, which is unlikely to be recoverable through wholesale markets alone. Revenues need to be sufficient and stable enough to provide sufficient return on investment in equipment costs for customers. Retail customers frequently demand a payback period of two years or less, an implied discount rate of roughly 20%, to make investments in energy efficiency or DR.

On the other hand, other stakeholders preferred that all funding for DR should come via the wholesale market; if costs can't be recovered from the market, either there is a problem with the market structure or DR isn't as valuable as current payments suggest, regardless of the Energy Action Plan's preferred loading order. Another advantage of relying on market funding is that it negates the need for contentious litigation and challenges surrounding cost-effectiveness evaluation methodology and inputs.

The stakeholders also noted that the CPUC and CAISO also have differing opinions regarding counting DR towards RA requirements. The CPUC has proffered that all approved DR programs qualify in meeting RA requirements. However, the CAISO has disagreed with qualifying emergency-triggered DR programs for resource adequacy that are available for dispatch only when minimum operating reserve margins are not met.

### RI.2 Political resistance to reflecting dynamic or locational pricing in retail rates

Efforts to implement area specific electricity rates in California are seen by stakeholders as likely to meet stiff political resistance. Some of the areas that would be expected to have higher nodal prices, such as San Francisco, are precisely those cities with greater political influence. According to stakeholders, the number of Default Load Aggregation Points in the initial release of MRTU was limited to three areas, reflecting the IOU service territories, in part due to political resistance to locational pricing.

Because nodal prices are not reflected in retail rates, it is impossible to align nodal prices paid for load curtailments and Default LAP prices charged for load procurement. Several stakeholders pointed out that this mismatch in prices can lead to gaming opportunities, cost shifting and perverse incentives.

Dynamic pricing does not face obstacles of the same magnitude in California. As described in Section 6, the state is in the process of making critical peak pricing the default rate for commercial and industrial customers. However, due to AB1X, default dynamic pricing for residential customers is effectively prohibited until the California Department of Water Resources supply contracts expire (see dynamic pricing discussion in Section 6)

### RI.3 Critical Issue - Mixed signals from 5% DR goal, EAP's loading order and cost-effectiveness protocols

The stakeholders see several differences between how the CPUC views successful DR programs versus how CAISO views DR in the wholesale market. For example, the CPUC has established the Total Resource Cost (TRC) test as the hurdle DR programs must pass to be considered cost effective, while CAISO's hurdle is whether or not the DR resource's competitive bid cleared the respective market. This difference is only further exacerbated by the Energy Action Plan II's stated loading order that requires energy efficiency and DR be considered before other resource types, including clean thermal resources. This particular disconnect exemplifies the interwoven nature of the many barriers identified.

Some stakeholders expressed concern and frustration that FERC's emphasis on promoting direct participation focuses on DR in isolation and out of context with respect to other California initiatives. The utilities in California that are currently the primary providers of DR programs face multiple policy goals that are not entirely consistent. The 2005 EAP set forth a goal of acquiring price-based DR equal to 5% of peak load. The goal was established on the principle that a small reduction in load during peak hours could significantly reduce energy prices and that DR would therefore prove cost-effective. This goal, many argued, focused the utilities on maximizing the quantity of DR enrolled, without placing sufficient emphasis on cost-effectiveness or on MW reductions that are dependable.

Subsequently, in 2007, the CPUC initiated a proceeding to establish load impact protocols and a cost-effectiveness methodology for DR programs. However, the requirement to achieve a significant amount of demand response with the 5% goal (which has been eased to some degree) and the requirement that DR be cost-effective have not been fully reconciled. Furthermore, establishing consistent cost-effectiveness criteria for DR has proven more difficult than for energy efficiency. In any case, the quantity target in the 5% DR goal and the cost-effectiveness methodology have no relation to the wholesale market capacity needs or prices.

### RI.4 Multiple initiatives overwhelming capacity of stakeholders and market participants

Many stakeholders indicated that it was difficult or impossible to adequately participate or follow the multiple proceedings that impact DR. Stakeholder comments were mixed with some believing this is a barrier to timely implementation of workable direct participation products. Others felt that a full plate of regulatory proceedings is business as usual and a challenge all parties have had to live with for some time. Following multiple proceedings is particularly problematic for small organizations with limited staff and for organizations that are not paid by their clients or customers to participate in stakeholder workshops or regulatory proceedings. A few stakeholders pointed out that intervenor compensation is available for participating in CPUC proceedings but is not available for CAISO stakeholder processes, limiting their ability to participate. A partial list of ongoing proceedings that impact DR includes:

- Multiple CAISO market design stakeholder processes
- CAISO Energy Storage Stakeholder Process and Pilot Program
- CEC Integrated Energy Policy Report
- CEC Title 24 Building Standards
- CPUC Long term RA proceeding
- CPUC DR load impact and Cost-effectiveness protocols
- CPUC Resource Adequacy Proceedings
- CPUC Smart Grid Proceedings
- IOU Default Dynamic and CPP rate applications
- IOU 2009-2011 DR Program Applications

Stakeholders also explained that it was difficult for them to take the time to fly to Washington D.C. to fully participate in FERC proceedings or respond to CAISO filings before FERC.

Other stakeholders felt that too much work on DR was being done in topical 'silos' with little respect to the impacts on other issues or proceedings. DR clearly involves both the generation and load side of the business yet the involved staff and stakeholders in each area are not usually well-versed in the other. With different working groups working on specific products or issues, solutions proposed in one area often create problems in another.

## 7.3. Customer Participation Barriers and Critical Issues

The barriers and critical issues identified in this section of the report were raised by a combination of the utilities interviewed, as well as the CSPs and stakeholder customer representatives. As noted above, these barriers and issues are discussed from the viewpoint of a customer who is considering participating in or providing DR resources into the California market, be it retail or via direct participation in the CAISO wholesale market.

### *7.3.1. Barriers*

**CB.1 Complexity of the DR market offerings from a customer's perspective**

In talking with the stakeholder customer representatives, as well as through customer interviews and focus groups over the past several years, it has become apparent that not only is price-based DR not as well understood as energy efficiency or reliability-based DR programs, but that it is a much tougher sell. This is based in part on a series of perceived realities that have been shared during the interviews and via related focus groups.

Frequently, the customers express a lack of appetite for the perceived risk of DR involvement and exposure to the complex, unpredictable and foreign wholesale electricity market. Their core business involves knowing how to make the best widget, not becoming energy traders or grid operators. In contrast, convincing a customer to change out their lights to CFLs is a straight forward, close to one time transaction, with the benefits driven by comparatively stable and transparent retail rates Behavioral-based response to DR involves much more commitment, both by the customer and their DR "sponsor" be it the LSE, CSP, or CAISO. The DR sales cycle can be much longer, with intermittent "hand holding" required in order to maintain a level of awareness, preparedness, and commitment among the customer base. Without that, the DR resource has a much higher probability of slipping away during those events when the system operators count on it being relatively robust. For more on the concerns regarding the uphill learning curve associated with valuing price-based DR among grid system operators, see the section on operations and settlements barriers below.

Multiple stakeholders were concerned with the level of time and effort required to educate even sophisticated customers about MRTU and the proposed PDR product to feel comfortable that they knew enough to make an informed decision. DR market rules are only slightly less complicated than those for generation. Customers, again focused on making widgets, have to become comfortable with the implications of Congestion Revenue Rights (CRR), loss factors, Default LAPs, Custom LAPs, baseline and impact calculations and performance penalties. From the customer's perspective, each element poses potential hidden risks and consequences. One stakeholder described receiving from a customer, following three years of preparation, three face to face meetings and numerous phone calls, an e-mail that stated, "too much to grasp at the moment, assume you will advise if need to take action."

In order to elicit interest among the customer base, DR offerings need to be simple, with consistent rules and expectations over time, so as to better tie into the customers' multi-year capital decision-making process, and provide a tangible benefit to the customer, be it being seen as a good corporate citizen, helping to comply with corporate climate change goals, cutting operating costs, or a combination of all of the above.

### *7.3.2. Critical Issues*

CI.1 Utilities, Regulators and CAISO underestimate the challenge of changing customer behavior

Many agree that the silver bullet for moving DR forward in terms of increased participation is to get customers enabled to respond via auto DR technologies or well-tuned and sophisticated energy management systems, and that those technologies remain within the management control of the customers.

While the legacy DR programs have had under-frequency relay triggers, which are clearly not within the control of the customers, the stakeholder interviews pointed out that all too frequently, utilities and regulators underestimate the resistance among customers to allowing direct utility or government control of devices that impact their business or home environments. A recent example in California involved the CEC's public retraction of a programmable communicating thermostat (PCT) standard. That standard would have required that the customer's over-ride of the control signal could itself be over-ridden to maintain grid reliability if the alternative were rotating black outs, thereby trumping the customer's ultimate control function.

As was mentioned earlier in the report, and based on 30 years of it being emblazoned across all forms of media and communications, customers understand energy efficiency, and immediately visualize it via the compact fluorescent light bulb. Similarly, more customers get emergency-triggered or reliability-based DR in that they have been around for some time, and more of the customer base can grasp the idea of cutting back in order to avoid rotating outages. One has to only look at the statewide Flex Your Power results to see evidence that the customers get it. However, when it comes to price-based economic DR, the person on the street/common customer has a much more difficult time understanding the concept as well as what tangible benefit (be it financial or otherwise) he/she will derive. This is especially true if there is a disconnect between what the actual retail price is based on and what the wholesale price drivers are. Again, look back to the 2001 energy crisis in California when wholesale prices were driving utilities towards (and into) bankruptcy in that there was no correlation to what they could charge customers. Nor was there much demand response from the customers who were not on the interruptible/curtailable tariffs in that their rates stayed unaffected.

As the long-time purveyors of the legacy DR programs, some stakeholders indicated that the utilities service and sales organizations often excel in the customer service and customer relations aspects of their job descriptions, but do not always shine when it comes to innovative marketing and sales strategies, thereby impacting the customer uptake on DR programs. This can be seen when talking with commercial/industrial customers in focus groups who routinely identify their utility account representative as their "go to" person when it comes to energy issues. In talking with customers, you will also hear that the CSP representatives are much more aggressive than their utility counterparts in closing the sale. While these perspectives can be legitimately viewed as an issue, they are significant in that in dealing with customers and their willingness to change (i.e., sign up for an altered form of utility service), perception is reality.

<u>CI.2 Based upon historical DR involvement, CAISO market requirements are likely ill suited for many customers' pursuing direct participation</u>

One of the goals espoused in Order 719 is that customers be able to directly participate in the CAISO wholesale markets. Stakeholders indicated that there are several reasons why this may be difficult in the near term, some of which have been interwoven in the discussion of other aspects of this study. These reasons include:

- The CPUC has not pursued the development of a forward capacity market in California, nor are DR resources able to directly contract for RA capacity payments. Absent an alternative source for capacity payments, it is unlikely that customers or CSPs will soon jump to a direct participation wholesale model given the payments available through IOU-managed programs.
- CAISO requires all participants to be, or be represented by, a certified Scheduling Coordinator (SC). In the future, if one assumes that the CSPs come to a point where they move away from the current bilateral capacity payment contract that they operate under with the utilities, they too could function as a scheduling coordinator for the aggregated load within their portfolio. Indeed, some CSPs have become SCs. In addition, some CSPs active in other markets have yet to enter the California DR market. However, the stakeholder interviews indicated that it was highly likely that the significant investment in time, resources, and costs associated with internally taking on the role of a CAISO-certified scheduling coordinator will keep almost all customers who opt to consider DR, doing so through their LSE or a CSP.
- These potential high cost/high risk options become even less attractive from a retail customer's perspective when one bears in mind that under the current retail DR program portfolio and accompanying bilateral contract mechanisms, they do not have to take on these exposures and costs in that they are in some respects "protected" from the wholesale risks by the CPUC, their load serving entity, and/or the CSP with whom they have contracted.

## 7.4. Technology and Infrastructure Barriers

### *7.4.1. Barriers*

**<u>TB.1 Infrastructure and systems costs associated with DR</u>**

Many stakeholders emphasized that the infrastructure costs associated with the CAISO market design and mapping millions of customers to thousands of nodes are not to be underestimated. Some are worried that the systems and processes necessary to map retail customers to nodes for purposes of participating in DR will prove costly. While the CAISO envisions that nodes will remain relatively stable, the utility distribution circuits that connect to those nodes are reconfigured and expanded over time. When dealing with millions of retail customers, it is not unreasonable to expect that changes in the linkage between customers and nodes might occur frequently. Others felt that the costs to implement the communication of scheduled loads and bills between the CAISO, utilities, CSPs, ESPs and retail customers will be significant. Utility software systems used in generation, distribution and retail business units often have difficulty communicating data within the company, much less to external parties. Unlike generation, DR requires a high level of coordination and communication with functional areas such as customer services and retail billing that have not historically required a great deal of interaction with wholesale procurement.

As stated previously, the CPUC has directed the IOU's to pursue alignment of DR resources with MRTU and CAISO markets. The utilities have raised some potential cost issues in addition to telemetry. Forecasting participating load will require modifying existing software, and DR programs are not integrated with the wholesale side of the utilities. Ultimately, the CPUC will need to review the costs associated with integrating utility DR programs into CAISO markets and enabling direct participation and determine if the benefit to ratepayers warrants the investment. As discussed above, there is some question as to whether wholesale markets will provide sufficient revenues to justify such an investment.

### 7.4.2. Critical Issues

TI.1 Scheduling Coordinator/Transmission level requirements for participating load

The CAISO currently requires any entity wishing to participate in its wholesale markets to become a Scheduling Coordinator. The CAISO uses the analogy of a brokerage firm holding a seat on a stock exchange. Companies seeking to participate directly on the exchange floor must buy a seat. Individual investors, on the other hand, open an account with a brokerage firm set up to handle large numbers of smaller customers.

Even so, some stakeholders are concerned that the metering and communications infrastructure will prove too costly for CSPs wishing to engage in direct participation with their DR customers. Some fear that the expected cost of telemetry needed to provide 4-second telemetry data will be exorbitant for all but the largest firms and thereby eliminate participation in ancillary services markets. Others question whether such requirements, designed for transmission level customers, are realistic or appropriate for DR programs that aggregate the loads of distribution level residential and commercial customers. As one stakeholder put it, generators expect to pay for telemetry in order to get their product to market; for demand, telemetry is an added expense that is unrelated to their business. These stakeholders are eager to see less onerous and costly requirements developed for aggregated DR programs, perhaps using sampling techniques.

TI.2 Limitations of AMI

The three IOUs in California are in various stages of rolling out AMI in their respective service territories. AMI has been promoted by the utilities as an enabling technology for dynamic pricing and DR programs. Many stakeholders emphasized, however, that the AMI systems currently being installed do not meet CAISO or WECC requirements for direct participation of load in AS markets. AMI meters for the mass markets will measure load on an hourly basis only, and do not communicate load data in real time, but record the data for periodic collection by the utility. As for the larger commercial/industrial customers, their meters have the capability to measure more discrete loads, down to by the minute. Clearly, AMI alone will not meet the AS market requirements for real-time communication and sub hourly interval data.

While interval meters will not facilitate participation in AS or 5-minute imbalance energy markets, they do enable participation in Day Ahead and hourly Real Time energy markets. For those markets, meter data that can be provided within the required settlement timeline is sufficient.

Other stakeholders emphasized AMI will facilitate DR participation for smaller commercial and residential customers only when end use appliances are able to communicate with the AMI systems. Such customers are not likely to actively watch energy prices but rather will expect load reductions to occur automatically in response to price signals. The design, production and adoption of such appliances will occur gradually over several years, and likely have little impact over the five year time horizon of this study.

## 7.5. Operations and Settlement Barriers

### *7.5.1. Critical Issues*

<u>OI.1 Inherent compromises in balancing multiple objectives of baseline methodology</u>

Stakeholder comments on baseline issues varied widely. All stakeholders recognized that baseline calculations would be inherently inaccurate and challenging. Some accepted these limitations and felt that reasonable solutions to baseline calculations could be developed despite the inevitable imperfections. Others saw baseline calculations as a more fundamental problem with the potential to frustrate timely or expanded implementation of direct participation.

Many argued that customer acceptance was the paramount concern. They saw a need for a single, uniform and transparent methodology that could be easily understood by customers. Multiple or complex methodologies, they feared, would only further discourage customers from participating in an already unintuitive DR landscape.

Others argued that accuracy is essential; otherwise DR would never be viewed as reliable or comparable to generation by system operators. Furthermore, only relatively accurate (and presumably more complex) methods could minimize opportunities for gaming.

Still others see the need to rely on baseline calculations in and of itself a fundamental flaw of DR. They feel baseline calculations will inevitably be inaccurate, potentially confusing and complex and provide gaming opportunities that cannot be effectively mitigated. They argue it makes more sense to charge customers for what they use, rather than to try to pay them for what they do not.

Stakeholders identified at least three different applications for baseline calculations, each of which might require a potentially unique methodology. Those applications are 1) impact estimates for forecasting and scheduling, 2) impact estimates for determining cost-effectiveness, and 3) baseline calculations for payment and settlement. It might be, for example, that the methodology for forecasting might err on the side of being more complex and accurate, whereas the methodology for payment is more transparent and simple to facilitate customer participation.

One example of the potential for confusion and controversy has already arisen. A staff report in the CPUC RA proceeding proposes that all DR aggregators must comply with the CPUC adopted DR load impact protocols. CPUC staff argues that use of the protocols is needed to quantify the DR impacts that will count towards RA. Several stakeholders, on the other hand, argued that those protocols were developed with a primary focus on long term planning and cost-effectiveness. Furthermore, they argue, the protocols contain many requirements related to determining cost-effectiveness that are not at all relevant for those CSP/ESP programs that are not ratepayer-funded. This is also an example of multiple processes proceeding in relative isolation and generating solutions and proposals that directly impact other areas.

### OI.2 Complexity of scheduling and settlement

Many stakeholders explained that it is difficult to clearly delineate the boundaries between parties scheduling the load and load reductions of DR customers. This is particularly problematic with direct access; utility or CSP DR customer portfolios may include both bundled and direct access customers whose load is embedded in the schedule submitted by the utility on the one hand and the ESP on the other. In the exchange of schedules and information between all the parties, it will be difficult to determine which enrolled DR MWs are or are not already included in the respective schedules submitted by utilities, CSPs and ESPs. For some this is an issue that can be resolved. Others feel the inevitable complexity, expense and labor required for the settlement process will pose a barrier to participation.

The complexity in scheduling and settlement is closely related to the technology and infrastructure barriers described above. One stakeholder described that the potential for things to fall between the cracks can pose risks significant enough to inhibit participation, or at least increase transaction costs. For example it is not always clear either within the utility or CAISO or between the different entities, what their different roles, responsibilities or capabilities are at different stages of the process. Different entities or departments often interpret a rule or tariff in dissimilar ways.

Multiple stakeholders raised the issue of the added complexity with CSPs bidding in DR resources from multiple LSEs and with DA customers participating in IOU and CSP offerings. To facilitate participation and avoid discrimination, DA customers are permitted to enroll in DR programs marketed by the IOUs and CSPs, and CSPs are permitted to enroll customers from multiple LSEs. The IOUs, however, may not act as a SC for the DA customers. In many cases the CSP is not an SC, so the CSP or customer must hire a third party to schedule for them. In such cases, the party responsible at each step of the scheduling and settlement process is not at all clear. In the words of a given stakeholder “this is one of 30 or more examples” illustrating that no one has a good comprehensive understanding of the process from start to finish.

Some stakeholders identified one aspect of the current PDR proposal as a potential barrier. DR bids in both the Day-Ahead and Real Time markets will be reflected in the LSEs day-ahead schedule. The load reductions realized due to DR bid in by a CSP will result in a cost savings to the LSE but no corresponding payment from the LSE to the CAISO or the CSP. Under the current proposal, there will be a need for payments from the LSE to the CSP to settle outside of the CAISO process. This will require individual bilateral negotiations between each CSP and LSE. Some stakeholders feel that the risk and transaction costs associated with such settlements occurring outside the markets could more than offset potential gains and therefore limit direct participation.

### OI.3 Potential for gaming due to differences between nodal and aggregated prices.

As with the issue of baseline calculations, opinions on the issue of nodal versus. aggregated pricing points and the resulting potential for gaming varied widely. Several stakeholders felt this was an issue that they expected to be satisfactorily addressed through stakeholder processes used in developing the PDR and Participating Load products. Others thought that different prices for load and DR payments would result in gaming which would discourage DR participants and result in an unacceptable level of cost shifting and discrimination.

Some see nodal pricing for load, DR and generation as the best or only way to achieve comparable treatment of resources and prevent gaming opportunities. Others believe the political reality is such that nodal pricing for load will not be seen in California for some time, if ever. For those stakeholders, it is therefore incumbent on the CAISO to develop a ‘second best’ product that acknowledges this reality, despite the potential for gaming.

Customers enrolled in Participating Load pay a nodal price as opposed to the Default LAP price for their load and are paid the nodal price for load curtailments. There is general agreement that only a limited number of large and sophisticated customers will use the Participating Load product, which is not designed for smaller customers or aggregated DR portfolios. However, this effectively limits the customers that may avail themselves of nodal pricing for load to a small number, and for some stakeholders, they see this as a discriminatory and untenable situation. Some argue that as long as the choice is voluntary, only those customers at low cost nodes consistently below the Default LAP would choose to participate. The customer would realize savings by paying a nodal price for load that is below the Default LAP. Payments for DR participation would be lower, but even with DR available year round, DR calls would be limited as compared to the savings for load achieved throughout the year. Others claim that this will not be a problem as only the LSE’s would see the nodal vs. LAP prices for load and that the customer would continue to pay retail rates and therefore would not perceive a cost savings for load. Other stakeholders argue that allowing only some customers to voluntarily shift from LAP to nodal pricing for load would essentially shift costs to the remaining customers who cannot.

PDR as proposed is designed for CSPs and aggregated portfolios of DR customers. Unlike Participating Load, it does not change the price charged for load. However, PDR does pay for DR at a Custom LAP (CLAP) that reflects the nodes at which customers in the DR portfolio are located. The load is priced at the Default LAP (DLAP) for the LSE whereas the DR is priced at the CLAP. This again creates gaming opportunities. If there are capacity payments for DR, customers would be encouraged to enroll premises at low cost nodes that are less likely to be dispatched for DR. On the other hand, customers in a high cost CLAP would have an incentive to over schedule load and offer DR, receiving DR payments for phantom load.

A few stakeholders commented that the differences between nodal and Default LAP prices could be reduced, though not eliminated, by increasing the number of LAPs from the current three in the initial implementation of MRTU. They suggested that this might be one potential measure to reduce gaming opportunities.

# 8. STAKEHOLDER FEEDBACK

## 8.1. Approach

The stakeholder mechanisms used in compiling this report consisted of two information and perspective gathering efforts; first preparing for and conducting a series of interviews with a cross-section of stakeholders to gain input and perspective, and second, a review of the study's preliminary findings through an April 8$^{th}$ CAISO-hosted webinar, duly noticed and advertised among not only the interviewed stakeholders but other stakeholders as well. Conducting the webinar was viewed as an effective and not overly time-consuming approach to allow all interested parties an opportunity to review and question the project team in terms of the preliminary barriers identified, as well as provide information for their use in developing any minority opinions to be shared with the project team.

## 8.2. Stakeholder Interview Process

Having completed the literature search described above, and collected very valuable insights from the prior DR barriers research already conducted at the national and state of California levels, the team prepared a draft questionnaire to be used in conducting interviews with key stakeholders in the California wholesale/retail market. This questionnaire was reviewed and improved by the CAISO Project Team, who also worked with the consulting team to identifying the key stakeholders and individual contacts. A copy of the questionnaire is included as Appendix B. Eleven interviews were conducted, involving approximately 30 individuals, all of whom demonstrated a working knowledge of some if not all of the aspects and nuances of demand response in California. The key stakeholders included individuals who represented the following perspectives;

- Investor-owned utilities (i.e., Pacific Gas and Electric, Southern California Edison, Sempra Utilities)
- Other LSEs (the California Department of Water Resources)
- Regulatory entities (including the CPUC's Energy Division)
- Curtailment Service Providers (EnerNOC)
- Consumer advocates (a representative from The Utility Reform Network)
- Customer representatives (California League of Large Electricity Consumers Association – CLECA; California Manufacturers and Technology Association - CMTA)
- Electric service provider representatives (Alliance for Retail Energy Markets (AReM); also a renewable resources representative)

In order to promote collection of frank input, the interviewees were guaranteed anonymity in terms of their specific comments, though they were informed that the study may identify positions that were taken amongst members of a given category. In some cases, the interviewees were comfortable being recorded to help ensure that the study's project team was capturing their thoughts; in some of these cases, the interviewees requested transcripts along with an opportunity to comment upon them. These were provided, with few corrections being noted. In other cases, the interviewees were not comfortable being recorded, so the interviews were conducted accompanied by copious notetaking.

In developing the preliminary findings associated with the barriers identified by the interviewees, the study team chose to limit the discussion to those barriers that were identified by more than one interview entity. This decision was made in order to focus the discussion on those barriers that seemed of significant concern to multiple stakeholders, rather than possibly representing the perception of single entity.

The preliminary findings were then used to develop the materials shared with the larger DR stakeholder community via the CAISO-sponsored webinar which was held on April 8, 2009. The webinar announcement was published on March 13, 2009, and noticed to all appropriate CAISO mailing lists. The webinar's presentation deck was posted on the CAISO website for potential attendees to review on April 6th, giving them a short window to review the material before the actual webinar was conducted. A copy of the presentation deck is included as Appendix C, which includes slide-specific comments provided by those nine participants who sent along written responses.

Approximately 50 stakeholders participated in the webinar, with some entities having more than one person on the call. While some participants could stay on the line for the full two hour session, others had to sign off earlier. A list of the participants is attached as Appendix D. A copy of the webinar transcript has been posted to the CAISO website's DR page and can be obtained there.

While a few questions were posed as the study team walked through the presentation deck (some of them inquiring as to who specifically was interviewed), most of the discussion followed the conclusion of the presentation. During the open discussion (which was moderated by the conference call coordinator), the discussion centered on:

- revisiting some of the identified barriers;
- talking about whether or not all points raised by the interviewees should be catalogued in the report to ensure a thorough vetting of the positions taken;
- whether and how the stakeholders would have an opportunity to review the draft study prior to its submission to FERC on April 28th;
- next steps that CAISO intends to pursue in terms of establishing action items associated with the identified barriers;
- the ability or lack thereof of Curtailment Service Providers (CSPs) participating in the wholesale market;
- impact on the level of DR resources available in the event that the proposed Proxy Demand Response (PDR) design is not approved and the view that without it, all DR would continue to have to come through a load serving entity. As such, FERC's goal of direct participation wouldn't be realized;
- potential shift of the California DR stakeholders' regulatory interaction from the state level to FERC, and the logistical problems as well as limitations that would create;
- additional discussion regarding the implications of WECC's current stance on DR not being eligible to play in all of the Ancillary Services market; and
- the relatively short window of time to provide written comments on the webinar content back to CAISO.

As the webinar was concluding, the participants were reminded that written comments would be due by the close of business on Friday April 17th. During that comment period, submissions were received from the following entities;

- Alliance for Retail Energy Markets
- BluePoint Energy LLC
- California Department of Water Resources – State Water Project
- California Public Utilities Commission (CPUC) staff
- CPower
- EnerNOC
- Grid Services, Inc.
- Pacific Gas & Electric
- Southern California Edison

A complete collection of the feedback received during the comment period is contained in both Appendix C, in those cases where the stakeholders had specific comments to make and Appendix D, where their overall general comments are collected.

# 9. PROPOSED SOLUTIONS

FERC Order 719 requests that ISOs describe any proposed solutions to the barriers identified, including a timeline for resolution. A number of the identified barriers will be addressed through current or planned initiatives. For each of the five categories of barriers, a table listing the barrier and proposed solution is provided below.

The barriers were subjectively prioritized into high, medium and low categories by the consulting team and the CAISO using two criterion. The first criterion is the degree to which the barrier inhibited comparable treatment of generation and DR resources. The resource comparability criterion is taken directly from the ruling by the Commission in Order 719. The second criterion was the degree to which the barrier inhibited the pursuit of increased participation of demand response in retail or CAISO markets.

Barriers were further characterized by the role that the CAISO can play influencing or developing proposed solutions. In some cases, barriers will be addressed directly by the CAISO through internal initiatives or stakeholder processes. In other cases, the CAISO has little direct authority and will play a more limited role as an advocate, participant or provider of information.

## 9.1. Market Solutions

The primary means for addressing market barriers will be the CAISO, in conjunction with its stakeholders, through developing viable and desirable wholesale demand response products. This includes the current development effort of the proposed Proxy Demand Resource product, and the refinements being made to the existing Participating Load Program. The CAISO will also continue to engage stakeholders in discussions regarding possible changes to facilitate increased alignment of retail DR programs with CAISO markets. For instance, as a result of such efforts, the IOUs, with CPUC approval, agreed to alter the trigger for a large portion of their reliability-based demand response from a 'Stage 2 Emergency' to a 'Warning, Stage 1 imminent', allowing the ISO to use DR resources prior to having to declare a Stage 2 emergency.

Some stakeholders would like to see the CAISO dedicate more staff resources to the development of PDR and demand response efforts, in general. Others asked for support in becoming a Scheduling Coordinator. The CAISO continues to consider resource issues, especially now that MRTU has been implemented. The CAISO plans to assist all entities interested in exploring or becoming a Scheduling Coordinator. The CAISO has an assigned individual in its External Affairs Department that is dedicated to helping market participants become Scheduling Coordinators.

In addition, the CAISO has supported the centralized capacity market concept proffered by the California Forward Capacity Market Advocates (CFCMA) and has stated that the CFCMA proposal "offers a solid basis for developing an effective central capacity market design. It will provide transparent prices and needed price signals for investment decisions and economic trade-offs among investments in new generation, demand response and transmission."[49]

| Barrier | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **MB.1** | **Resource Adequacy (RA) Capacity payments are elusive for DR resources directly participating in the CAISO markets outside of a retail DR program** | High<br>Advocate | CAISO actively participate in current and future CPUC DR and RA proceedings to ensure greater alignment and comparability between retail and wholesale DR revenue streams. |
| **MB.2** | **Lack of a transparent, forward capacity market for direct participation DR resources** | High<br>Advocate | Continue to engage stakeholders and the CPUC in the Long Term RA proceeding (R.05-12-013) to determine the appropriate mechanism for clearing RA capacity. Work with stakeholders and CPUC to address how DR resources can access RA capacity payments. |
| **MB.3** | **WECC standards preclude DR resources from participating in regulation and spinning reserve markets** | High<br>Direct | CAISO will launch an initiative to evaluate the ability to revise definitions of existing AS products to ensure technology neutrality, seeking FERC approval and WECC alignment. |
| **MB.4** | **Customers accustomed to existing investor-owned utility programs** | Low<br>Limited | Continue engagement with stakeholders to develop viable wholesale DR products with direct participation capability. Work with stakeholders and the CPUC on greater alignment between retail programs and wholesale products. |

[49] See page 2 in the CAISO's Reply Comments of The California Independent System Operator to Comments on Staff's Modified Centralized Market Proposal, R.05-12-013, December 15, 2005 found at: http://www.caiso.com/205b/205b87ea72510.pdf

| Critical Issue | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **MI.1** | Attributes of existing programs poorly aligned with CAISO markets | High<br>Advocate/ Direct | Pursue greater alignment through CPUC DR OIR (CPUC R.07-01-041), and other relevant CPUC proceedings, CAISO stakeholder process and CAISO market and product design efforts. |
| **MI.2** | CSPs[50] precluded from direct participation without FERC approval of the PDR product | High<br>Direct | Continue PDR stakeholder process targeting May 2010 implementation. Stakeholder support in the design and approval of wholesale DR products. |
| **MI.3** | IOUs will likely remain a key player in offering DR to retail customers, and will take direction from the CPUC and CEC, not CAISO | Medium<br>Advocate | CAISO will continue to participate in CPUC DR and other relevant proceedings with goal of increasing alignment of utility programs and facilitating direct participation of DR resources. |
| **MI.4** | Various DR Market Vision perspectives among stakeholders | Medium<br>Inform | Promote understanding of CAISO policy and positions through participation in relevant CPUC proceedings. |

## 9.2. Regulatory Solutions

WECC rules prohibiting participation of DR resources in all ancillary services markets, including spinning reserves and regulation, was the barrier most commonly cited by the interviewed stakeholders. The CAISO will pursue definitional and technical changes, as appropriate, to ensure these ancillary services can be provided in a technology neutral way while maintaining reliability and performance standards. Some stakeholders also advocated developing a 30-minute reserve product that would be more conducive to a wider range of participating load types. Initiating further pilot programs, such as the current Participating Load Pilot projects may help demonstrate the potential for certain types of load to reliably participate in these markets.

[50] For the sake of simplicity, the term Curtailment Service Provider or "CSP" will be used to refer to any non-utility DR provider, although utilities do sometimes refer to themselves as a CSP with respect to the direct participation of utility managed DR programs. It may also be possible for ESPs to act in the role of a CSP for DA customers.

| Barrier | | Priority<br>CAISO Role | Solution |
|---|---|---|---|
| **RB.1** | **Fundamental policy differences between the wholesale (FERC/WECC/CAISO) and retail (State Legislature/CPUC/CEC) perspectives** | High<br>Policy Reconciliation | Pursue greater alignment through CPUC DR OIR (CPUC R.07-01-041), and CAISO stakeholder process. |
| **RB.2** | **Regulatory driven retail programs limit growth opportunity for CSPs** | Medium<br>Limited | Work with CPUC and stakeholders to ensure better alignment between retail and wholesale DR programs. Continue to develop and refine the direct participation capability of DR resources, including the ability to access RA and A/S capacity payments. |

| Critical Issue | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **RI.1** | Program value may not be fully recovered in wholesale market, limiting incentives for direct participation | High<br>Policy Reconciliation | Continued CAISO engagement in the CPUC DR OIR- Cost-effectiveness proceeding (CPUC R.07-01-041) as well as informing interested parties about the plethora of performance reporting processes conducted and published by the CAISO. Such reports, especially with MRTU market data incorporated, should help better inform this issue over time. |
| **RI.2** | Political resistance to reflecting dynamic or locational pricing in retail rates | Low<br>Inform | CAISO products such as PDR (if approved) and Participating Load enable demand response providers to earn the locational marginal price for load curtailments. The CAISO's market produces and publishes locational marginal prices, reflecting the cost of consuming energy at specific times and places on the grid. The CAISO's market design establishes a solid foundation for the CPUC to consider incorporating dynamic or locational pricing into retail rates. |
| **RI.3** | Mixed signals from 5% DR goal, Integrated Energy Policy Report (IEPR) loading order and cost-effectiveness protocols | Low<br>Policy Reconciliation | Remain engaged in CPUC DR OIR (CPUC R.08-06-001) and follow Long Term Procurement Proceeding (CPUC R.08-02-007); this is a longer-term barrier that is engrained in and integral to the state's long-term procurement policies. |
| **RI.4** | Multiple initiatives overwhelming capacity of stakeholders and market participants | Low<br>Participant | Promote initiatives through and utilization of the "Market Initiatives Roadmap" |

## 9.3. Customer Participation Solutions

It is possible that the CAISO will need to add additional staff resources, on par with ISOs in the eastern states, to facilitate direct participation by non-utility DR aggregators. Given the great deal of uncertainty and differing opinions regarding DR, the FERC or ISO/RTO Council may wish to fund a market study to identify load types and market segments most and least likely to participate in wholesale markets. This would help focus DR product development efforts and minimize time and effort spent developing rules and regulations for products with limited actual participation.

| Barrier | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **CB.1** | **Complexity of the DR market offerings from a customer's perspective** | Low<br>Direct | CAISO to develop and offer a structured bid-to-bill DR training program for market participants |

| Critical Issue | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **CI.1** | Utilities, Regulators and CAISO underestimate the challenge of changing customer behavior | High<br>Direct/Policy Reconciliation | Continue targeted pilot projects to inform the overall DR development process and overcome technical and integration issues. Continue reliance on stakeholders involvement in the development of viable and attractive DR products |
| **CI.2** | Based upon historical DR involvement, CAISO market requirements are likely ill suited for many customers' pursuing direct participation | Medium<br>Direct | CAISO Participating Load pilot projects will inform and provide lessons learned and seek better, easier to implement, more cost-effective alternatives to integrating DR resources in CAISO markets. |

## 9.4. Technology and Infrastructure Solutions

The CAISO, in coordination with PG&E, SCE and SDG&E, is conducting Participating Load Pilot projects to better understand, among other things, the technology and infrastructure needs around integrating residential, commercial and industrial aggregated demand response resources into the CAISO markets. One of the key objectives of the pilot projects is to find IT solutions around metering, notification, and telemetry that are cost-effective, easy to implement, and meet the CAISO's performance and reliability standards. The CAISO expects results and lessons learned from the first phase of these pilot projects to be available for review by the end of the year.

| Barrier | | Priority / CAISO Role | Solution |
|---|---|---|---|
| **TB.1** | **Infrastructure and systems requirements and costs associated DR under MRTU** | Medium<br>Inform | Develop and provide market participants with clear specifications about system and business requirements. Current activities and forums are helping to elicit these requirements include the Participating Load pilot projects, CAISO Business Issues and Processes working groups, and on-going/evolving CPUC policy on how "locational" it wants to make DR as a resource or as a dynamic rate. |

| Critical Issue | | Priority<br>CAISO Role | Solution |
|---|---|---|---|
| **TI.1** | Scheduling Coordinator/Transmission level requirements for participating load | Low<br>Direct | Engage and walk CSPs through the CAISO's SC Application Process. CAISO provides single point of contact for any entity interested in becoming an SC. Documentation is published and available on how to become a SC with overview materials.[51] |
| **TI.2** | Limitations of AMI | Low<br>Participate | Address through CAISO Business Issues and Processes working groups; tighter coordination/ communication between CAISO and utility AMI and DR staff |

## 9.5. Operations and Settlement Solutions

On April 30, 2009, the CAISO is hosting a stakeholder meeting where it will be initiating a structured working group process to discuss and resolve the issues around the direct participation of demand response participating under the proposed PDR product in the CAISO markets. For example, the CAISO has already identified as a priority in the PDR stakeholder process the development of systems that link the CSP and LSE into the CAISO's settlement process. The CAISO will also continue to participate in the CPUC DR Proceedings and, with stakeholder input, determine if and how the CPUC Load Impact Protocols might apply in the CAISO markets, initially in terms of how applicable relative to the proposed PDR product.

| Critical Issues | | Priority<br>CAISO Role | Solution |
|---|---|---|---|
| **OI.1** | Inherent compromises in balancing multiple objectives of baseline methodology | High<br>Direct | CAISO Business Issues and Processes working group plans to address this issue early and sees it as highest priority. |
| **OI.2** | Complexity of scheduling and settlement | Medium<br>Direct | CAISO to develop and offer a structured bid-to-bill DR training program for market participants. |
| **OI.3** | Potential for gaming due to differences between nodal and aggregated prices | Low<br>Direct | Gaming opportunities viewed as limited in nature; will be handled through market monitoring and specific market design elements targeted to address specific potential gaming concerns. |

[51] http://www.caiso.com/docs/2005/10/05/2005100520241822328.html

# ATTACHMENTS

Appendix A – Literature Review

Appendix B – Interview Guide

Appendix C – Webinar Presentation (with stakeholder notes)

Appendix D – Webinar Participant List

Appendix E – Stakeholder General Comments

Appendix F – Direct Participation Business Issues Working Groups

# APPENDIX A: LITERATURE REVIEW

National Demand Response Documents

- Assessment of Demand Response & Advanced Metering, FERC Staff Report (December 2008)
- Demand Response and Smart Metering Policy Actions Since the Energy Policy Act of 2005: A Summary for State Officials, The National Council on Electricity Policy (Fall 2008), U.S. Demand Response Coordinating Committee
- National Perspective on Demand Response, The Brattle Group presentation at the California Energy Commission, March 5, 2008
- Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them, A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005 (February 2005)
- "The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response". With Nicole Hopper, Charles Goldman, Ranjit Bharvirkar (LBNL-62754). The Electricity Journal, Vol. 20, Issue 5, June 2007, pgs. 62-75.
- "Demand Response Program Design Preferences of Large Customers: Focus Group Results from Four States". Electricity Markets and Policy Group, Lawrence Berkeley National Laboratory. With Terry Fry and Robert Hinkle, Nexant, Inc. (LBNL Report 60610). June 2006.

California-specific Demand Response Documents

- Demand Response 2009-2011 Program DR filings, party comments, data request responses to the CPUC by PG&E, SCE, and SDG&E CPUC A.08-06-001 http://docs.cpuc.ca.gov/published/proceedings/A0806001_doc.htm
- The State of Demand Response in California, Draft Consultant Report, California Energy Commission, Brattle Group, April 2007
- CAISO Demand Response Tactical Plan Final Draft, December 31st, 2007 (is this public?)
- CAISO Demand Response Vision and Strategy, Draft Report, Freeman, Sullivan, & Co.; Summary provided to CAISO's Market Issues Forum on January 25, 2007
- DR Vision Statement – Prepared by the CPUC, For Discussion by the Vision for Demand Resources Working Group (2007)
- DR focus group results culled from multiple sessions held with PG&E and SCE commercial/industrial customers (2006 – 2008)
- California Customer Load Reductions during the Electricity Crisis: Did they Help to Keep the Lights On? *Charles A. Goldman, Joseph H. Eto, and Galen L. Barbose.* Energy Analysis Department. Ernest Orlando Lawrence Berkeley National Laboratory. University of California Berkeley. May 2002
- Overview of California ISO Summer 2000 Demand Response Programs. John H. Doudna, P.E, Senior Member, IEEE California 1S0 Operations Engineering Dept. IEEE. 2001.
- "Energy Division's Report on Interruptible Programs and Rotating Outages." Filed with the California Public Utilities Commission under Proceedings for R. 00-10-002, February 8, 2001
- CAISO Annual Report. 2001
- "Measurement and evaluation of energy efficiency programs: California and South Korea". E. Vine, C.H. Rhee, and K.D. Lee. Energy 31 (2006) 1100–1113

- California Public Utilities Commission. Decision 02-10-062. Interim opinion, Oct 24, 2002. San Francisco, CA: CPUC; 2002.
- "California Demand Response: A Vision for the Future (2002-2007)" included in D.03-06-032 as Attachment A. http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/26965.ht
- 2009-2011 Demand Response Program Filings. CPUC Application 08-06-001, 08-06-002, 08-06-003. Filed June 2, 2008.
- “Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies - Part 2”. Energy Central (June 18, 2007).
- Press release, Itron, Gas & Electric Chooses Itron OpenWay® for Smart Meter Deployment (July 30, 2008). http://www.itron.com/pages/news_press_individual.asp?id=itr_016717.xml
- “Advanced Metering Infrastructure: The Regulatory Context.” Presentation to EDF by Tom Roberts, CPUC. June 23, 2008
- “California’s Demand Response Policy: The Policy Context for AMI.” Presentation to EDF by Bruce Kaneshiro. June 23, 2008
- SDG&E’s 2008 General Rate Case, A. 07-01-047
- Assembly Bill 1X 29 from the 2001-2002 First Extraordinary Session, Section 14(d)(4)(B).

CAISO Documents

- CAISO DR Participation Guide - version 3 dated November 29, 2007
- CAISO MRTU Release 1 Provisions to Support DR –DRAFT ONLY
- MRTU Release 1 Participating Load Users Guide (technical standard in revision mode)
- Original Straw Proposal for Post Release 1 MRTU Functionality for DR (before direct participation functionality was being considered) dated 11/9/07
- Direct Participation Issue Paper dated 12/22/08
- DR Business Process Issue Framework
- Stakeholder Comments on Direct Participation Issues
- Alternative Proxy DR Proposal as submitted by SCE dated December 2008
- CAISO Demand Response Strategic Initiative Program Overview Presentation. February 16, 2009.

## APPENDIX B: INTERVIEW GUIDE

**CAISO DR BARRIERS STUDY**
**STAKEHOLDER QUESTIONNAIRE**

MARCH 19, 2009

**Introduction**

You may recall that the Federal Energy Regulatory Commission (FERC) issued Order 719 on October 17, 2008. Among other things, this order required each RTO and ISO to assess and report on the barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction (Paragraphs 724 through 726). We have been commissioned by the California ISO to assist in preparing the required DR Barriers Study and submitting it to FERC as part of the compliance filing due on April 27, 2009.

By sharing your perspective on the various topics noted below, as well as others that you deem to be important, you will be providing valuable insights that will be considered for inclusion in the study. Your help is much appreciated.

The questions shown below provide a framework around which to gather your input, and also help ensure that the basic questions we pose to the various stakeholders interviewed are at least somewhat consistent. That being said, the structure is more than flexible enough to accommodate delving into other areas where you see significant barriers in place. We intend for this interview to be more of a dialogue rather than an interview in which you simply answer our questions.

Based on the wide range of entities being interviewed, we have categorized the questions based on those we feel may be most relevant to the various types of interviewees. Again, this is not cast in concrete, but will hopefully allow us to spend the time focusing on those areas of most interest to you.

Following completion of our numerous interviews, we will compile an initial review of our summary findings, which will inform the development of the CAISO's DR Barriers Study, and will also provide additional content for a stakeholder webinar that CAISO will host on April 8th.

Assumptions driving the DR Barriers Study

- California focus
- Barriers not issues

*Bear in mind that the focus of this interview is on barriers that may inhibit or significantly delay DR participation in the CAISO markets. The questions below* *make a distinction between "direct participation", which refers generally to DR participation in CAISO markets, and "utility programs", which are managed by the California utilities and may or may not participate in CAISO markets.*

**General Questions**

1. In which of the following markets do you expect direct DR participation to provide the most value, both in terms of maintaining system reliability and enhancing market efficiency, and in terms of economic incentives for participation?

    - Resource Adequacy Capacity
    - Day Ahead Energy
    - Real Time Imbalance Energy
    - Ancillary Services

2. How are differing performance requirements and standards for reliability and ancillary service products set by NERC, WECC and/or other agencies a barrier to direct DR participation?

3. What, if any, are the barriers to the active participation in these markets by utility DR programs, CSP's, or individual customers?

4. What barriers must be addressed in the design and implementation of the CAISO's markets to promote direct participation?

5. In the world of direct participation in the CAISO markets, how do you see the utility DR programs playing and in which markets?

6. What resolution do you foresee regarding the RA treatment of some of the legacy DR resources that do not conform to a standard RA product definition (e.g. emergency-only programs)?

**LSE Perspective Questions**

7. Does the form of the Resource Adequacy Capacity Market (i.e. bilateral versus a centralized capacity market), pose a significant barrier to direct participation?

8. The CAISO currently plans to implement Participating Load with the initial release of MRTU in April of 2009. Which barriers, if any, are the most likely to impact the implementation or utilization of Participating Load.

9. The CAISO currently plans to implement its Dispatchable Demand Resource (DDR) with in April of 2010. Which barriers, if any, are the most likely to impact the implementation or utilization of DDR?

10. The CAISO currently plans to develop and implement its Proxy Demand Resource (PDR) by May 2010. Which barriers, if any, are the most likely to impact the implementation of PDR by May 2010?

11. DR in California is dominated by utility programs funded by ratepayers and reviewed by the CPUC.

    - How well aligned are the legacy programs with the current and proposed CAISO markets?
    - What are the critical barriers to the participation of such programs in the CAISO markets by 2012?
    - Do you foresee a world where the CAISO market revenue streams replace CPUC and utility DR funding mechanisms?

12. Would it be possible to link the program payments for utility DR programs to the market value they would receive in the CAISO markets? What are the challenges in this type of transition?

13. CSP-delivered DR programs are currently funded via bilateral contracts with the utilities, and rely predominately on capacity payments. How should revenues earned via direct participation affect the bilateral contracts or utility incentives paid to CSP's?

14. Do you consider the challenges associated with marketing, customer awareness, and customer uptake to be issues or barriers?

15. Are there systems and infrastructure that will be needed that may pose a barrier to direct participation if not funded or developed (repeat from LSE section)

**<u>Regulatory Perspective Questions</u>**

16. DR in California is dominated by utility programs funded by ratepayers and reviewed by the CPUC. (repeated from LSE Section)

    - How well-aligned are the legacy programs with the current and proposed CAISO products and markets?
    - What are the critical barriers to the participation of such programs in the CAISO markets by 2012?
    - Do you foresee a world where the CAISO market revenue streams replace CPUC and utility DR funding mechanisms?

17. Would it be possible to link the program payments for utility DR programs to the market value they would receive in the CAISO markets? What are the challenges in this type of transition? (repeated from LSE section)

*Alignment of CPUC and CAISO*

In the Rulemaking 07-01-041 (DR OIR) scoping document, the fourth purpose of the proceeding was to "Consider modifications to DR programs needed to support the California Independent System Operator's (CAISO) efforts to incorporate DR into market design protocols." (See http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64245.htm)

18. How would you rate the progress the OIR has made in this in general? How about specifically:

    a) in the load impact protocols?
    b) in the cost effectiveness protocols?
    c) in specifying / coordinating the times when programs are called?
    d) in the payment of DR resources to CSP's?
    e) in the calculation of DR program benefits for utilities?
    f) in payments to customers?
    g) in locational dispatch ('right place, right certainty')
    h) in the ability to call DR 365 days vs. limited frequency
    i) in addressing value of DR in renewables integration with 33% RPS

19. The CPUC evaluates utility DR programs based on cost-effectiveness protocols using an avoided cost methodology (for capacity, energy, T&D etc.). FERC seeks to have DR participate in capacity, energy and ancillary service markets on a 'comparable' basis to generation, and be paid market-based prices. In what ways do the 'program' vs. 'market' based approaches pose a barrier to direct DR participation? Which approach is the best way to establish and capture the value of DR?

20. What do you see as the most significant barriers in aligning the utility DR programs with the CAISO efforts?

21. How well is the CAISO's DR stakeholder/working group process mentioned in the DR OIR scoping document working in aligning utility programs with CAISO markets?

*CPP Related Questions*

22. What do you think is a reasonable timeline for having price-responsive DR that is coordinated with the CAISO?

23. California utilities are in various stages of implementing default CPP tariffs. What do you see as the major obstacles to default CPP?

24. In the development of the proposed default CPP tariffs, is there an explicit (or implicit?) link to the value of RA, real time energy, or other CAISO markets in setting the CPP rate? Are current approaches (such as a 3x or 5x multiplier for the peak TOU period) without a link to CAISO markets appropriate for default CPP programs?

25. In the development of the proposed default CPP tariffs, how should the times when the CPP is dispatched be determined (e.g. SDG&E: when forecast temperature is >84º and prior day's load reaches 3,837 by 2:30 pm)?

26. It is possible that default CPP for C&I customers could exceed the 5% peak DR goal for price responsive programs. Do you think this is possible or likely?

27. Is the goal of enrolling 5% of peak load in DR programs appropriate? If not, what alternative approaches or methodology should be used to set appropriate MW goals for DR programs of different types (i.e. emergency, incentive based, dynamic pricing)?

**Stakeholder Perspective Questions**

28. The CAISO currently plans to implement Participating Load with the initial release of MRTU in April of 2009. Which barriers, if any, are the most likely to impact the implementation or utilization of Participating Load? (repeat from LSE section)

29. The CAISO currently plans to implement its Dispatchable Demand Resource (DDR) with in April of 2010. Which barriers, if any, are the most likely to impact the implementation or utilization of DDR. (repeat from LSE section)

30. The CAISO currently plans to develop and implement its Proxy Demand Resource (PDR) by May 2010. Which barriers, if any, most likely to impact PDR's implementation by May 2010? (repeat from LSE section)

31. With the current bilateral CSP contracts appearing to have relatively substantial capacity payments, and the possibility that these same payment streams may not be achievable in the CAISO markets, what is the advantage for you in pursuing direct participation instead?

32. CSP programs are currently funded via bilateral contracts with the utilities, and rely predominately on capacity payments. How should revenues earned via direct participation affect the bilateral contracts or utility incentives paid to CSP's? (repeated from LSE section)

33. Is a bilateral versus centralized market for Resource Adequacy a significant barrier for direct participation? (repeat from LSE section)

34. How will the CSP contracts need to be revised when direct participation becomes a reality?

35. Do you consider the challenges associated with marketing, customer awareness, and customer uptake to be issues or barriers?

36. Are there systems and infrastructure that will be needed that may pose a barrier to direct participation if not funded or developed (repeat from LSE section)

37. Would having different baseline methodologies adopted by the CAISO and CPUC pose a barrier? How about different baseline methodologies used for impact estimation vs. settlements?

**Wrap-Up Questions**

38. What issues regarding the implementation of markets for direct participation, if any, do you feel rise to the level of a barrier that has the potential to inhibit or significantly delay direct participation at the CAISO? Potential examples include:

    - Settlement prices for load versus DR
    - Potential for gaming
    - Missing money
    - Settlement and scheduling processes
    - Maintaining linkage between LSE, CSP and retail customer
    - Level of certainty and transparency for payments and settlements
    - Baseline methodology
    - Technology costs

39. What barriers, if any, exist in terms of:

    - Plethora of DR initiatives both locally and on the national level vis a vis resources available
    - Regulatory/jurisdictional linkages
    - Value streams and the CAISO market products

40. Which barriers, if any, deserve more attention or resources than they are currently receiving?

What other programs/initiatives compete with DR implementation for attention and resources? Are there political, regulatory, financial or other considerations that might prevent direct participation from receiving the attention and resources from your organization necessary for timely implementation?

# APPENDIX C: WEBINAR PRESENTATION WITH STAKEHOLDER NOTES

## APPENDIX D: WEBINAR PARTICIPANT LIST

| | |
|---|---|
| ***To:*** | THOMAS CUCCIA |
| ***E-mail Address:*** | tcuccia@caiso.com |
| ***Conference ID #:*** | 992119 |
| ***Company Name:*** | CALIFORNIA ISO |
| ***Host's Name:*** | THOMAS CUCCIA |
| ***Name of Conference:*** | DEMAND RESPONSE |
| ***Date of Conference:*** | WEDNESDAY, APRIL 08, 2009 1:00PM PACIFIC |

| | NAME | COMPANYPHONE |
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| 4. | BERGAM, BRIAN | SUMMIT ENERGY |
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| 13. | GILLETTE, MELANIE | ENERNOC 916 501-9573 |
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| 20. | HIRTH, SCOTT | SOUTHERN CALIFORNIA EDISON |
| 21. | HOBBS, BEN | CALIFORNIA ISO |
| 22. | JERMAIN, DAVE | SOUTHERN CALIFORNIA EDISON |
| 23. | JUNG, GIFFORD | POWEREX 604 891-6040 |
| 24. | KOTT, ROBERT | CALIFORNIA ISO |
| 25. | KRUTH, MAURY | FERC 916 294-0275 |
| 26. | LEE, KENNY | CALIFORNIA ISO |
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| 30. | METTLING, RICH | BLUEPOINT ENERGY |
| 31. | MILLER, MARGARET | CALIFORNIA ISO |
| 32. | NELSON, MICHAEL | MCCARTHY & BERLIN |
| 33. | NICHOLSON, RANDY | SAN DIEGO GAS & ELECTRIC |

34. RAFAEL, CHRIS — CALIFORNIA ENERGY MARKETS
35. REED, DAVID — SOUTHERN CALIFORNIA EDISON
36. REXROADE, KAREN — CUSTOMIZE ENERGY SOLUTIONS
37. REXRODE, KAREN — CUSTOMIZE ENERGY SOLUTIONS
38. ROCHLIN, CLIFF — SOUTHERN CA GAS COMPANY
39. SARROKHPAY, SAEED — FERC 916 294-0322
40. SCHNEIDER, SUSAN — PHOENIX CONSULTING
41. STOWE, DERICK — PACIFIC GAS & ELECTRIC
42. TIERNEY-LLOYD, MONA — ENERNOC 805 995-1618
43. TOCA, CHARLES — UTILITY SAVING
44. TONG, JIE — CALIFORNIA ISO
45. VAWTER, VONDA — CORPORATE SYSTEMS ENGINEERING
46. VILLARREAL, CHRIS — CALIFORNIA PUC
47. WOLAK, FRANK — MARKET SURVEILLANCE
48. WOOD, KEVIN — SOUTHERN CALIFORNIA EDISON
49. WYNNE, JUSTIN — CALIFORNIA MUNICIPAL UTILITIES
50. WYNNE, MICHELE — GRID SERVICES
51. XIE, JUNE — CALIFORNIA ISO
52. ZHANG, XIAO — PACIFIC GAS & ELECTRIC

# APPENDIX E: STAKEHOLDER GENERAL COMMENTS SUBMITTED POST WEBINAR

## Alliance for Retail Energy Markets (AReM) Comments

1. Use of Term "Hybrid Market" — This term has been used commonly in California to describe the current generation market, in which utilities may build and own their own resources in competition with independent power producers. You use the term differently. To avoid confusion, we suggest that you use a different term to explain the demand response market in CA.

2. Administrative Rule Requiring One Scheduling Coordinator/Meter — This CAISO rule is a barrier to direct participation by DR providers and customers. This rule should be mentioned under "Operation and Settlement Barriers."

3. Need to Provide Information on Proposed Solutions and Timetable for Implementation — The April 8 presentation was basically a laundry list of issues/barriers affecting DR in California. We have no information on which of these issues/barriers the CAISO believes to be most critical, nor on the CAISO's proposed solutions and timetable, as required by FERC Order 719. AReM is concerned that the CAISO plans to move forward with its filing to FERC without effective stakeholder review or engagement on these issues.

## Blue Point Energy LLC Comments

BluePoint Energy, LLC is a DR Aggregator in California. Its business is the control and maintenance of demand side resources. In light of our experience in California BPE is concerned with four barriers to larger DR participation.

1. Restricted CAISO market participation for Utility DR Program participants.
2. Appropriate DR A/S market products.
3. Registration and credit requirements.
4. Resource aggregations.

If these barriers were lowered more DR projects could be justified in California.

### Description of Barriers

### Restricted CAISO market participation for Utility DR Program participants.

**Utility and CAISO programs** are in conflict. Utility DR Programs are the best source of Capacity Revenue for DR resources, but once committed to a Utility DR program; participation in CAISO A/S and Energy markets requires CPUC approval. This situation limits DR market access for Non-Spin and energy and limits participation of dispatchable demand resources. It seems only reasonable that a resource be allowed free access to A/S and load markets when DR programs have not been triggered. The additional revenue would incent more resources and enable expansion of DR.

### Appropriate DR A/S Market Products.

Current A/S products work well for generation but is not tailored to the demand side. .ERCOT currently purchases **Responsive Reserves** which may be actuated by under frequency relay or proportional response to frequency. These ancillary services are very compatible with DR and deserve consideration. Similar frequency response services haves been discussed in WECC for generation but have not been implemented. Implementation of a market for such a service, with DR resources in mind could provide additional and very beneficial reliability resources and additional revenue incentives for DR.

### Registration and Credit Requirements.

More liberal credit requirements and registration procedures should be required of Curtailment Service Providers (CSPs). ISONE, NYISO and PJM all provide unique registration processes for CSPs.

### Small Resource Aggregations.

Bidding and scheduling along with telemetry could be simplified if Curtailment Service Providers could **aggregate resources by load pocket.** With sub megawatt resources the cost of each installation is quite important and aggregations have the potential of lowering costs and encouraging market entry.

## California Department of Water Comments

To comply with FERC Order 719, CAISO hired consultants to aid in developing a Demand Response Barriers Study (DRBS). As part of this study various CAISO Market Participants (MP), including CDWR-SWP, were solicited for comment regarding their organizations view on market or technical barriers to participation in Demand Response programs within California. As a follow-up to this solicitation, CAISO held a conference call on April 8, 2009 to review MP comments and a list of barriers to be included in the DRBS. Unfortunately, the list of barriers presented did not contain all of the concerns provided by CDWR-SWP during the process. The explanation for this exclusion by CAISO and their consultants was that unless a position or barrier to demand response is voiced by more than one MP or group, it would not be included in the DRBS due to be submitted to FERC on April 28, 2009.

CDWR-SWP feels the DRBS would be incomplete without the inclusion of specific concerns especially since, through CAISO's Participating Load program, CDWR-SWP is the largest individual Demand Response (DR) provider in California. Within the five categories of barriers listed during the April 8 conference call, CDWR-SWP reiterates the following concerns as barriers to demand response,

1. Market Barriers
    a. DR participation not being on a voluntary basis (per FERC Order 719).
    b. Lack of competitive Market products such as Voltage Support, RAS, Under Frequency Load Shedding (UFLS) that all MP can provide.

2. Regulatory Barriers

a. Lack of Time of Use (TOU) pricing.
b. Participating Load Agreement (PLA) is not insulated from constant changes in Tariff, BPM, and/or Operating procedures.
c. When BPM, Operating Procedures, and computer applications are not in line with approved tariff. (Repeated below in 5.)
d. Lack of appropriate treatment for DR as load or generator, with respective service, costs, or payment. When load has chosen not to provide DR it is not being treated as firm load. DR is being charged firm load costs when receiving lesser quality service, i.e. interruptible. When load is providing DR, pay is not comparable to generators.

3. Customer Participation Barriers (no additional comment)

4. Infrastructure and Technology Barriers (no additional comment)

5. Operations and Settlements Barriers
    a. BPM, Operating Procedures, and computer applications not being in line with approved tariff.
    b. Settlement mechanisms addressing concerns of high LMP customers hide price signals.
    c. Settlement rules/systems that cause unfair cost socialization and do not follow cost causation principles.

**CPUC General Comments**

The CPUC staff appreciates the opportunity to review the input stakeholders have provided to FSC and E3 regarding the potential barriers to direct bid-in of California retail customers into CAISO's markets as DR. The CPUC staff understands that the responses provided in the April 8th, 2009 presentation are those of market participants and do not necessarily reflect the views of CAISO. With that in mind, the CPUC staff will limit its comments to matters where 1) there appears be a lack of clarity in the response as presented by FSC and E3, 2) there appears to be a misunderstanding by the stakeholder, 3) the CPUC staff either views the barrier differently or as not a barrier at all, 4) the CPUC staff comments may be able to add clarity, or 5) a barrier is not addressed.

**CPower General Comments**

CPower, Inc. ("CPower") is pleased to provide comments on the **California Background and Demand Response Barriers** presentation, dated April 8, 2009 ("DR Barrier Study").

Before moving to direct comments, CPower would like to commend CAISO on their effort to comply with the FERC Order 719 directive and to capture in a succinct and easy-to-understand form the issues and barriers preventing greater demand response participation in the CAISO markets. CPower appreciates the collaborative approach taken by CAISO to incorporate stakeholders' perceived barriers to direct participation, and we intend to continue to work with CAISO as this initiative moves ahead.

Overarching Comment

CPower would like to note that the sheer quantity of issues and barriers identified on the slides might lead a reader to conclude that progress to a properly demand-responsive market in California is either impossible or will take many years to implement. While all of the information is valuable and requires consideration, CPower believes that many items identified as "barriers" are in fact issues that can be readily overcome, or are currently managed in other organized markets or by standard CSP business practices. CPower has identified some specific items later in this response.

Barriers That Are Not Included

CPower believes that there are two major barriers that have not been included or are not called out (and so can be dealt with) in a sufficiently isolated way.
The first is that in an energy market, where the only reward for load curtailment is the avoided cost of energy at that moment, significantly undervalues the service provided and will never create any meaningful participation except in situations of extreme energy costs. This issue is identified in various forms and in various places (bullet 3 on slide 18 and bullet 3 on slide 19, slide 20 etc.), but CPower believes it is of sufficient importance that it requires a separate section. An energy-only compensation approach would lose the significant benefit of generally reduced energy prices to all electricity consumers in the state if the true value of demand response is not included in the rewards for demand-side participation at the wholesale level. This value includes the avoided capacity costs of replacement generation. This is recognized by many of the current programs in the state operated by the utilities, but even here, as Slide 12 shows, DR value is generally far below replacement capacity cost. Underpayment for provided service will be the primary barrier to further DR participation, and CPower does not believe that the current wholesale market design must preclude full compensation.

The second major barrier that CPower believes is not adequately addressed is direct discussion of the barriers to meeting the requirement (shown in item 5 on Slide 2, FERC order 719) which states "Permit a DR aggregator to bid demand response on behalf of retail customers directly into the organized energy market". The primary barrier here, and as shown on slides 9 and 10, is the difficulty of the scheduling, settlements and cash flows created by the overly complex hierarchy that exists in the management of electricity supply in the state. In other states, the ISOs manage, at little additional expense, to enable a more uniform treatment of LSEs and CSPs which flattens and simplifies this structure and eliminates many of the problems. In California, CSPs are essentially denied access to direct DR participation in the wholesale markets by the current market structure. Again, while several slides allude to this item, CPower believes that the barriers to meeting this FERC requirement should be addressed directly.

## **EnerNOC General Comments**

EnerNOC supports CAISO's efforts to comply with the FERC Order 719 directive to "study and report on whether further reforms are necessary to eliminate barriers to demand response in organized markets." EnerNOC appreciates the collaborative approach taken by the CAISO to incorporate stakeholders' perceived barriers to direct participation in organized markets, and we intend to continue to work closely with CAISO staff and stakeholders to ensure that CAISO rules provide for Curtailment Service Providers (CSPs) to participate directly in CAISO's wholesale markets.

While EnerNOC understands the timing and resource constraints that require stakeholders to comment on the April 8 presentation rather than the study itself, it should be noted that this is more challenging and may not entirely capture the spirit and tone of the final study. For example, by trying to capture stakeholder feedback in bullet form, many of the perceived "barriers" sound overwhelming and insurmountable, and EnerNOC does not believe it is the intention of the CAISO or its consultants to portray the challenges to direct participation as insurmountable obstacles but rather as barriers that can be eliminated, in many cases, through existing CAISO initiatives.

Barriers That Are Not Included
EnerNOC has identified some barriers to direct participation that do not appear to be reflected in the presentation. Perhaps the most significant barrier is not included because it is obvious, but it should be included. CSPs cannot currently participate in CAISO markets. EnerNOC is actively participating in the stakeholder working group to identify issues associated with implementing Proxy Demand Response (PDR), which would allow CSPs to bid directly into CAISO energy markets, but CSPs are currently not allowed to participate in these markets. The DR Barrier Study should expressly call this out as a barrier.

Another barrier that is not directly included in Slide 36, *Operation and Settlement Barriers,* is a direct consequence of the current PDR proposal, and EnerNOC will be highlighting this concern in its comments on the recently-released Draft Final Proposal on PDR. However, since PDR is being proposed as the vehicle for DR to directly participate in CAISO markets, it is appropriate to highlight this barrier here as well. Under the PDR proposal, the LSE's day-ahead schedule will be adjusted to reflect DR bids in both the Day-Ahead and Real Time markets. There will not be uninstructed deviation charges that CAISO will owe to the LSE. However, it is understood that there will be a need for the LSE and the CSP to settle outside of the CAISO process for something equivalent to uninstructed deviations. EnerNOC has raised the concern about a lack of transparency into the secondary settlement since it will occur in the context of a bilateral arrangement between the CSP and the LSE and outside of organized markets. This secondary settlement could eliminate any economic opportunity for direct participation of CSPs, require separate and potentially very dissimilar bilateral negotiations with each LSE and, thus, has the potential to be a significant barrier.

One additional barrier should be included in either slide 33 or 35, “Infrastructure and Technology Barriers.” The WECC telemetry requirements are a real barrier, but the requirement to have only one Scheduling Coordinator (SC) per meter is also a significant barrier to direct participation as it prohibits service from an LSE and a different CSP to the same customer.

Issues Improperly Defined as Barriers

It would be helpful if there was more clarification around how the study defines “issues” and “barriers.” EnerNOC believes that a number of the barriers identified in the presentation are more appropriately classified as issues or challenges rather than barriers to direct participation.

**Grid Services, Inc.**

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April 17, 2009

John Goodin
Lead, Demand Response
Regulatory & Policy Department
California ISO
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**Subject: Response to Demand Response Barriers Study Conference Call**

Thank you for the opportunity to comment on the information provided during the subject conference call. Grid Services, Inc. (GSI) began our involvement in Demand Management (DM) program during the run up to opening the CAISO. We were active participants in the process of developing protocols to allow loads to participate in the CAISO market. We were also active in the design of and participation in the Demand Response Program launched by the CAISO to meet energy shortfalls projected for the summer of 2000.

We applaud the decision to involve general stakeholders in the process. We are pleased with the breadth of material covered and the number of barriers identified.

We are disappointed with the decision to include only barriers identified by two interviewees. This decision puts into question compliance with the stated objective to "Insure minority views are represented and clearly identified." GSI suggests providing a list of all responses in the appendix.

The balance of the document presents a summary of our belief that the centralized electricity market model presents a barrier to the deployment of demand programs. This is followed by a short comment on each of the barriers presented during the conference call.

**Centralized Electricity Markets as Barrier to Demand Programs**

GSI believes that the centralized market form, structure and operation are perhaps the single largest barrier to Demand participation in the wholesale market. First, the focus on price optimization in a 10 minute window constrains all but the most flexible thermal unit. Second, the burden of participation (fees, credit, infrastructure, payment timeline) limits access to grid information on a timely basis. Third, the lack of market transparency including timely pre-operating period congestion information means that customers lack the ability to avoid congestion pricing.

The first step is to make more ISO data available to non-participants. For example, today the new LMP OASIS does not produce any data when queried. The old OASIS site has no data past March 31. The old OASIS data provides demand data by IOU. No data is available by either takeout point or congestion node. This significantly hampers the development of DM programs that might warn customers of impending price increases.

To clarify, let me provide and example of a central grid operator with greater transparency. Transpower is the "ISO" for the New Zealand deregulated market. On their website, they post the demand in MW for each of their load zones every 5 minutes. There is only a few minute delay from the close of the operating period and the posting of the flows. (See http://www.systemoperator.co.nz/n1944,download=true.html.) If additional granularity is required, the Electricity Commission will send you a DVD each month with 30 minute load data for each of 200+ GXP or Take-out Points. This information is used by an none market participant to forecast possible congestion and trigger DM programs that avoid congestion pricing.

A second step is to create a new class of participant with less onerous participation requirements that can accommodate entities that do not need the full range of market opportunities, scheduling and settlement processes that a Scheduling Coordinators enjoy.

**Market Barriers**

**Existing IOU Programs.** We agree. Our experience has been that a well thought out program that recognizes and accommodates customer concerns and issues could be successfully marketed to IOU customers.

**Poor Alignment with CAISO markets.** We agree. The CAISO market has a very short term horizon (10 minutes) and assumes that all participants will be in the market and willing to be dispatched. DM in the wholesale market is a reserve product that frees generation to participate in the market and delays the introduction of additional generation that would have marginal utilization. Increased ISO transparency that would allow DM participants to forecast ISO calls can increase the predictability customers require.

**RA/Capacity market not well suited**. We agree. The lack of a multi-year power purchase agreement structure hinders both generation development and DM. One solution is for the CAISO to return responsibility for short and long term procurement to the LSE, following the protocols of non centralize market grid operators and focus on only procuring load following services and managing reliability.

Centralized vs bilateral capacity market. We prefer bilateral markets because they allow for customized products that meet the unique requirements of each party. And they allow the flexibility to incorporate new ideas and strategies as they develop. We believe the Eastern market favor the generator. PJM was originally developed by State regulators with the capacity requirement introduced to compensate IOUs for generation that have above market costs under the PJM Pool system. The LSE pays an implicit capacity payment for Firm generation and then a second for the mandated Capacity.

**WECC regulation and spinning AS Markets**. We agree. FERC should direct NERC to review their rules to clarify the requirements for each service but not dictate how those requirements are met.

**Gaming and Cost-Shifting**. We agree. We cannot change to a more equitable process without data transparency and the time to execute strategies that minimize congestion and their related costs. The CAISO should publish all the historic and real time flow data and customer pricing for each of the LMP node points. Let the stakeholders find ways of profitably avoiding LMP in high-risk areas. Set a date in the future when load will be exposed by node and allow the local regulatory authorities decide how to allocate the costs.

**Regulatory Barriers**

**CSP/ESP Programs**. We agree. A solution is to make DM subsidies and revenues separate from the utilities. This is a State issue. The CAISO should create a less expense, non-SC centric process for compensating CSP/ESP for DM programs. The process should be a supplier settlement system separate from the load settlement process.

## Grid Services, Inc.

**FERC/CAISO vs CEC/CPUC.** We agree. The FERC/CAISO is mindset is supplyside focused, dispatchable thermal generator mindset. The CEC/CPUC mindset is demand focused, specifically in reducing the cost of supply to customers. A start is for the CAISO to become more transparent in the load flows, pricings and operating decisions. By transparent, we mean post load, real-time pricing and final settlement data on a public website. This will allow State bodies to develop better programs to avoid wholesale costs. For example, the State could support a program that monitored flows at congestion nodes and curtailed load when approaching flows that would trigger congestion pricing. This is a non-market solution. The State can spread the cost across the area customers because it reduces overall energy costs and postpones grid upgrades.

**Dynamic or LMP in Retail.** We agree. If the CAISO cannot tell me until tomorrow or next week what it cost me to consume today, then I agree with the State that dynamic pricing is not appropriate. If a gas station operator changed the price of gas while I pumped it into my car, we would have him arrested for fraud. The CAISO should provide sufficient transparency to forecast flows and possible congestion. When the CAISO produce an indicative electricity price far enough in advance of the operating period to allow customers to avoid price changes, then dynamic pricing might be appropriate.

**Costs Not Recovered In Wholesale Market**. We agree. All of the value associated with a DM program does not come from the wholesale market. DM can be used to delay generation development and grid expansion.

**Mixed signals for 5% DR, etc.** We agree. There should be no assumption at all DM value comes from the wholesale market. Many DM programs may not have any CAISO involvement. What is of concern is insuring that the CAISO does not unnecessarily constrain none market initiatives.

**Multiple Initiatives**. We agree. We propose that all FERC meetings and discussions related to Western DM projects be held either over the Internet on in the West.

## Grid Services, Inc.

**Customer Participation Barriers**

**Underestimated Challenges.** We agree and disagree. *We agree* that Utilities and regulators do not have the mind set for developing out of the box solutions and that utilities are not great at marketing. *We disagree* that customers cannot understand the economics. Our experience as been that a properly constructed marketing effort results in very little trouble presenting the concept to customers.

**Complexity of Market**. We disagree. This is a marketing issue. It is a matter of identifying which product matches a customer's profile and making the program understandable from the customer's viewpoint. For example, customers are able to decide on a car or truck or suv from the copious options available.

**CAISO Market Requirement Ill Suited**. We agree. The CAISO market is designed for dispatchable thermal generation. They have had difficultly integrating wind into their market. The CAISO needs to create layers of markets that accommodate the increasing divergent suppliers and insure that their rules do not prohibit none market DM activities.

**Infrastructure Barriers**

**SC/Transmission Level Requirements.** We agree. The requirements for participation in the CAISO market are burdensome and a significant barrier to entry. A more simplified process should be adopted for entities not providing load following-regulation services.

**Customer LMP mapping**. We disagree. The process for identifying a customer's Load Takeout Point existed in 2000 when IOUs were required to identify the grid settlement point each the customers going to an ESP. The Takeout Point was assigned to the meter not the customer.

**Limitation of AMI.** This is somewhat irrelevant. AMI have the ability to be polled at intervals of less than 1 hour. We established in 2001 that a DM service that needs to be deployed in no less than 10 minutes does not require 4-second SCADA. The solution was the polling of load meters, aggregation and providing aggregated data to the EMS system every 4-seconds. As for other technology to manage appliances, they existed for at least a decade. They will be deployed when there is sufficient incentive.

## Grid Services, Inc.

**Operational Barriers**

**Load Forecasting Challenge.** We agree. The is a lack of available public data on historic and real time flows at the nodes used to calculate nodal prices. Once that data becomes available there are several load forecasting companies capable of developing and offering products that can provide the CSP with the information they need.

**Separating DR Capability**. The CAISO can create a mini-SC that function to provide the interface between them and the DM providers. Specifically, the flow of money should not have to go to the SC providing customer load settlement data.

**Lack of Operator DM Experience.** We disagree. The CAISO has direct experience with the DSM program for several summers starting in 2000. The program worked because the aggregators revenue dependent on successful curtailments.

**Balancing Multiple Objectives of Baseline Methodology.** So long as the methodology basic and not We agree so long as the methodology basic and not proscriptive. One size does not fit all.

Again, thank you for the opportunity to provide comments.

Sincerely;

Michele Wynne, President

**PG&E Comments:**

- The CAISO's Draft Demand Response Barriers Study was well organized and provided a thorough reflection of the diverse comments from all the major stakeholders. It is PG&E's understanding that the CAISO will be adding a prioritization of the barriers to the report as well as a plan to address the barriers. We understand that the CAISO will include these additional thoughts in its filing to FERC on April 28, 2009, and that stakeholders will have the opportunity to comment on the CAISO's filing after it is submitted. PG&E would prefer to provide our comments before the CAISO files, but we understand the time constraints and may comment on the CAISO filing after we have reviewed it.

- PG&E sees the highest priority barriers that need to be addressed as the following:

  - Time
    - We understand that it will take time to work through many of the issues that need to be resolved in order to most effectively integrate DR into the CAISO markets. PG&E does not believe that this process needs to be slow. However, the process should be carefully designed and should be implemented deliberately and efficiently. DR bidding into a complex market needs to be done with care so that the benefits are realized.
    - Issues that will require time to develop include:
      - Full deployment of smart meters
      - Linking wholesale prices to retail rates
      - Telemetry/EMS/SCADA infrastructure
      - Ability to measure and accurately forecast loads at comparatively fine geographic granularity
      - Local regulatory authorities (e.g. CPUC) setting rules that allow their parties to offer DR products to the CAISO.
      - Getting the CAISO and WECC product requirements (particularly ancillary services) to be based on functional needs rather then the traditional characteristics of generation.
      - Details on processes for "bid to bill" for DR. This is a major reason why significant time is needed to implement DR directly bidding in to the CAISO markets. This implementation will require significant infrastructure upgrades. This work includes upgrading IT infrastructure as well as other business processes and systems.

  - It is essential that the CPUC and the CAISO closely coordinate to develop a plan for the implementation of DR. Many important policy issues will require a coordinated response from the CPUC and the CAISO, including the development of the criteria and rules that will allow third parties to bid in the customers of IOUs directly to the CAISO.

## SCE Comments

Southern California Edison's Comments on DR Barriers Webinar Presentation

SCE appreciates the opportunity to provide comment to the CAISO on its April 8, 2009 Webinar Presentation entitled "Demand Response Barriers Study". SCE provides general and specific comments on the CAISO Webinar presentation deck below.

Order 719 imposes an obligation on the CAISO to identify and remove unreasonable barriers to treating demand response resources comparably with other resources, so any barriers identified in the CAISO's report to FERC need to carefully articulate the specific regulatory or institutional constraints that should be overcome to maximize the effective utilization of demand response resources in CAISO markets.

SCE is concerned that the CAISO Webinar Presentation appears to label any issue or concern as a "DR Barrier" implying that the role of the CAISO in compliance with FERC 719 is very extensive and overwhelming. Also, some of the asserted "barriers" include redundant descriptions of the same underlying issue, framed in a somewhat different manner. SCE agrees with CAISO that there are many issues and concerns that must be addressed and serious effort by CAISO and stakeholders is necessary to resolve them. However, SCE recommends that CAISO define its compliance challenges in accordance with FERC Order 719's term "unreasonable barriers" rather than issues. Accordingly, SCE recommends that the CAISO adopt a definition of a "DR Barrier" and separate out barriers from issues and concerns. The CAISO compliance filing should contain all of the content of the Webinar with the content separated under headings such as "DR Barriers", "Critical Issues" and "Other Issues and Concerns".

Accordingly, SCE proposes the following definition of a DR "Barrier":

> A regulatory or institutional constraint that prevents an efficient amount of demand response from participating in CAISO markets.

Based on the proposed definition above, SCE finds that the following items identified in the webinar presentation should be included as DR Barriers in the report to FERC:

- Lack of a forward capacity market that would provide participating DR loads with appropriate longer-term price signals to offer DR as a capacity resource.
- Existing WECC and CAISO rules that preclude participation by DR loads in regulation and spinning reserve markets and limit participation by DR loads in non-spinning reserve markets.
- Complexity of "open" regulatory initiatives (such as resource adequacy, direct access resumption, renewables integration, and retail rate design reform) that make it difficult for stakeholders to actively engage in finding solutions to the problems of integrating DR with CAISO markets.
- The necessity to treat load consumption and demand response as parts of an inseparable system has been a barrier to direct participation. Approval of proxy demand resource (PDR) will address this barrier.

# APPENDIX F: DIRECT PARTICIPATION BUSINESS ISSUES WORKING GROUPS

## 1.0 Qualification

| Process | Description | Affected Entity |
|---|---|---|
| Product/Program Definition | Defining the various DR markets, products/programs, objectives, participants, requirements, operating rules, and success criteria | ISO, Stakeholders, Participants, |
| Participant Qualification | Criteria and process for determining market participation | ISO, Stakeholders, Participants |
| Resource Qualification | Criteria and process for determining resource participation prior to enrollment in a product/program | ISO, CSP |
| Integration to Registration | Method for ensuring smooth process transition from qualifying steps to actual resource enrollment in product/program | ISO |

## 2.0 Registration

| Process | Description | Affected Entity |
|---|---|---|
| Resource Profiling | Defining the demand response characteristics of a resource to be registered | CSP |
| • Unique Identifiers | Method for identifying a given resource uniquely across multiple participants | CSP, UDC, LSE |
| • Reduction Capacity/ Profile | Sources and capacity of demand reduction resources | CSP |
| • Shutdown Costs/Time | Parameters for consideration in bidding and dispatching events | CSP |
| • Shutdown Response Time | Amount of notice necessary for shutdown operation | CSP, Participant |
| • LMP and/or Retail Rate | Determining the price(s) and formula to be used in settlement | CSP, LSE |
| • Retail Contract Type | Type of retail energy contract | CSP, LSE |
| • Baseline Approach | Method of calculating load baselines for deriving a reduction | CSP, LSE |
| • Telemetry | Method and granularity of data | CSP |
| • Aggregation | Approach to handling a resource that is an aggregate of other individual resources | CSP |
| Program Enrollment | Method of registering a given resource for a given program for a given length of time | CSP, LSE, UDC, ISO |
| Enrollment Duplicates | Method of identifying and resolving duplicate enrollment, or other prohibited combinations of enrollments | CSP, ISO |
| Enrollment Disputes | Method of submitting, tracking, and resolving enrollment disputes | CSP, LSE, UDC, ISO |

| Process | Description | Affected Entity |
|---|---|---|
| Enrollment Changes | Method and rules for requesting changes to a registration or resource profile | CSP, LSE, UDC, ISO |
| Resource Transfers | Method and rules for transferring resources from one participant (CSP or LSE) to another | CSP, LSE, UDC, ISO |
| Testing & Auditing | Method and rules for periodically testing and auditing the reported resource reduction capacity | CSP, ISO |
| Integration to Scheduling | Method for ensuring smooth process transition from registration to the actual scheduling of resources into the market | ISO |

## 3.0 Scheduling

| Process | Description | Affected Entity |
|---|---|---|
| System Forecasting | Incorporating demand resources into the long and short term forecasting processes | ISO |
| • Load | Forecast of load with and without inclusion of price sensitive or emergency interruptible load | ISO, LSE, CSP |
| • Reduction Capacity | Forecast of reduction capacity given seasonal or secular variations of load and interruptible load | ISO, CSP |
| • Transmission Constraints | Impact of transmission constraints on the need for or use of demand resources | ISO |
| • Planned Outages | Forecast of demand resource outages, or other outages that might require the use of reduction capacity | ISO, CSP, LSE |
| • Reliability | Any other reliability review process that might need to incorporate demand resources | ISO |
| Resource Forecasting | Participants providing long and short term estimates of load and reduction capacity | CSP, LSE, Participant |
| Resource Scheduling/ Bidding | Actual participation in the various markets | CSP, LSE |
| • Resource Identification | Method of identifying the resource to be scheduled, on both the load and demand sides | CSP, LSE |
| • Resource Location | Method and granularity of identifying the network model location of the resource | CSP, LSE |
| • Resource Aggregation | Method and approach for allowing the participant to aggregate resources together when scheduling | CSP, LSE |
| Resource/ Schedule Alignment | Method of correlating CSP and LSE resources schedules with each other | CSP, LSE |
| Integration to Operations | Method of informing grid operations of demand resource schedules, and/or allowing them to dispatch capacity | ISO |
| Integration to Settlements | Method of informing settlements of market awards | ISO |

## 4.0 Notifications

| Process | Description | Affected Entity |
|---|---|---|
| Forecasts | Method for collecting and/or distributing demand resource forecasts | ISO, CSP |
| Self-Schedules | Method and timing for collecting and/or distributing demand resource self-schedules | ISO, CSP |
| Day-ahead Schedules | Method and timing for distributing demand resource day-ahead market awards | ISO, CSP, LSE |
| Real-time Dispatch | Method and timing for distributing demand resource real-time market energy dispatches | ISO, CSP, LSE |
| Ancillary Services | Method and timing for distributing demand resource ancillary service instructions, especially for real-time synchronous reserve and regulation | ISO, CSP, LSE |
| Emergency Reserves | Method and timing for communicating emergency events and/or dispatching specific reserve capacity | ISO, CSP, LSE |
| Outages | Method and timing for collecting and/or distributing demand resource outage information | ISO, CSP, LSE |
| Event Tagging | Method for uniquely identifying demand response events | ISO |
| Integration to Settlement | Method for informing settlements of what events occurred during real-time operations | ISO |

## 5.0 Metering & Telemetry

| Process | Description | Affected Entity |
|---|---|---|
| Metering Provider | Identifying the meter data source for given registration | ISO, CSP, LSE, UDC, MDMA |
| Metering Validation | Verification of in-place meter | ISO, MDMA |
| Data Availability | Ability to provide timely meter & telemetry data for DR event | ISO, MDMA |
| Data Type & Granularity | Type and granularity of data being provided | ISO, MDMA |
| Data Accuracy | Accuracy of meter and telemetry data being provided | ISO, CSP, MDMA |
| Integration to Settlement | Method for communicating summarized, aggregated, and validated interval data to the settlements process | ISO |

## 6.0 Settlement

| Process | Description | Affected Entity |
|---|---|---|
| Event Prioritization | Determining which events to settle for what resources and in what order | ISO |
| Determinant Collection | Identifying and collecting all the required bill determinants to settle a specific event for a specific | ISO |

| Process | Description | Affected Entity |
|---|---|---|
| | resource | |
| Baseline Calculation | Method for calculating a baseline from which a load reduction will be determined | ISO |
| Reduction Calculation | Method for calculating the actual load reduction | ISO |
| Settlement Calculation | Method for calculating the actual settlement | ISO |
| • Day Ahead | Cash flow model for cleared DA demand bids | CSP, LSE |
| • Real-time | Cash flow model for RT dispatched demand | CSP, LSE |
| • Ancillary Services | Cash flow model for AS provided by demand resources | CSP, LSE |
| • Emergency | Cash flow model for called emergency resources | CSP, LSE |
| Settlement Approvals | Method of submitting demand response event settlements for approval prior to actually billing/crediting | ISO, CSP, LSE, UDC |
| Settlement Adjustments | Method of re-calculating and submitting settlement adjustments | ISO, CSP, LSE, UDC |
| Settlement Disputes | Method of submitting, tracking, and resolving settlement disputes | ISO, CSP, LSE, UDC |
| Integration to Performance Management | Method for communicating settlement information to the performance management process | ISO |

## 7.0 Performance & Compliance Evaluation

| Process | Description | Affected Entity |
|---|---|---|
| Resource Performance | Measuring and reporting the activity and performance of resources | ISO, Participants |
| Participant Performance | Measuring and reporting the activity and performance of participants | ISO, Participants, Stakeholders |
| Program Performance | Measuring and reporting the activity and performance of participants | ISO, Participants, Stakeholders, Regulators |
| System Performance | Measuring and reporting the net effect of all demand response programs on reliability, market prices, etc | ISO, Participants, Stakeholders, Regulators |