BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011

TESTIMONY OF DR. BARBARA R. BARKOVICH
ON BEHALF OF THE
CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

May 6, 2014

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011

TESTIMONY OF DR. BARBARA R. BARKOVICH
ON BEHALF OF THE
CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

I. Introduction

Q1. Please state your name and business address.

A1. My name is Dr. Barbara R. Barkovich. My business address is Barkovich & Yap, Inc., P.O. Box 11031, Oakland, CA 94611. My statement of qualifications is included as Appendix A.

Q2. On whose behalf are you presenting this testimony?

A2. I am testifying on behalf of the California Large Energy Consumers Association (CLECA). CLECA is an organization of large industrial electric customers of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE). These companies are in the steel, cement, industrial gas, pipeline, mining and beverage industries and they share the fact that electricity costs comprise a significant portion of their costs of production. Some of the CLECA member companies are bundled service customers and some are served under direct access arrangements. For all of them the cost of electricity is a very important element in their cost structures and the competitiveness of their products.

Q3. Why is CLECA interested in this proceeding?

A3. All CLECA members participate in utility demand response (DR) programs. Most participate in both the Base Interruptible Program (BIP) and Demand Bidding Program (DBP), a combination of DR programs where dual participation is authorized. They therefore have considerable experience with DR and I, as their consultant, do as well. CLECA members are strongly interested in the future of DR in California and, assuming the requirements and compensation are commercially reasonable, how they may continue to participate.

Q4. Please describe the structure of your testimony and summarize the key points.

A4. My testimony follows the set of questions set in the Phase 2 Scoping Ruling dated April 2, 2014. It is separated into Sections pursuant to the Scoping Ruling and, to the best of my ability, the answers address the questions although they may not respond to each sub-question. My key points are:

- It is premature to set goals for demand response now; the goals should be informed by the record under development in this track and the experiences of at least this summer;
- Since all demand response affects resource requirements for Resource Adequacy, the Commission must ensure that all demand response is taken into consideration and affects procurement requirements and levels;
- Costs associated with integration into CAISO markets can reduce the cost-effectiveness of supply resource demand response programs, and integration costs imposed on individual customers and the system as a whole must be mitigated to avoid rendering such demand response programs cost-*in*effective;
- Two criteria should be used to categorize demand response programs as supply resources: first, whether CAISO dispatch is required for the program to provide its intended service; second, whether the integration costs are not so great that they make the program cost-*in*effective;

- There are many threshold questions on the demand response auction mechanism that need to be worked through before its implementation, even on a preliminary basis;
- It is not necessary to include reliability demand response in the auction mechanism;
- The apparent assumption that the federal Net Benefits Test is a substitute for a Commission determination on cost-effectiveness is misguided;
- Forecasting the impact on the load shape of dynamic pricing and having the CAISO take that impact into account is just as important as expanding dynamic pricing;
- Longer budget cycles and program stability are warranted;
- Regulation of back-up generation should be left to federal, state and local air quality agencies charged with regulating air quality;
- The Commission should set workshops to see if Load Serving Entities and other interested stakeholders can agree on a resolution of cost-recovery and related issues.

II. Goals for Demand Response

Q5. The first questions in the Scoping Memo address goals for demand response.

- Parties should provide what they consider to be past and current goals for demand response so that this proceeding has a complete and accurate history of the goals.
- Parties should provide recommendations for increasing individual demand response program load impacts and overall participation in demand response programs. If parties consider the current demand response participation level to be appropriate, please explain why.
- Parties should provide recommendations for developing the goals of demand response load (MW) and demand response participation, how those goals should be measured (load impact protocol based on ex post or ex ante, or others), and how often they should be measured to ensure goal achievement(monthly, seasonally, or annually)
- Parties should provide recommendations for programs or activities to ensure quality for load modifying resources and supply resources. Parties should suggest a definition for equality. (Scoping Ruling, Attachment A, at 1)

What are your recommendations as to goals for current and future DR for the California investor-owned utilities (IOUs)?

A5. It is premature to set new numeric DR goals. Previous numeric goals were arbitrary (e.g. a 2009 decision that 10% of utility DR programs be compliant with the California Independent System Operator's (CAISO's) Proxy Demand Resource[1]), and did not distinguish types of DR other than reliability vs. price-based. In this proceeding, the Commission is considering bifurcation of existing DR into two new categories, load modifying and supply resources, as well as adding additional resources to each category. Since the Commission intends to determine the characteristics of these two categories in this track of the proceeding, it is premature to set goals for either until this track has been completed.

The Commission's broad goal should be to develop all cost-effective DR, consistent with the loading order. However, for the DR to be deemed "cost-effective", its development requires an analysis of costs and benefits. For this reason, any future numeric goals should be based on a well-informed analysis and take into account the various services that DR can realistically be expected to provide and the costs and benefits of doing so.

Q6. Do you have a recommendation as to how the Commission should go about setting goals in the future?

A6. Yes. The Commission should pursue the following process to set supportable goals. First, the Commission should determine the services it wants DR to provide.[2] Second, the Commission should decide whether it is necessary for those services to be integrated into the CAISO markets. I propose as a key

[1] D. 09-08-027, at 130.
[2] Later in this testimony I propose a set of services and discuss them in some detail.

criterion for integration that the CAISO would need to dispatch the DR for it to provide the desired service. The third step would be to assess the costs and benefits of using DR for the service, including the costs of integration into the CAISO's markets, if necessary. If DR must be integrated into the CAISO markets to be dispatched to provide the service, but the cost is prohibitive, the Commission should reconsider using DR for such a purpose until there is a successful effort to reduce integration costs.

Only after performing this analysis will it be appropriate to set goals, based on cost and effectiveness. Competitive procurement may be a means to reduce costs or to bring forth new, creative applications of DR, but it is not a substitute for these other steps.

Q7. Couldn't goals be set based on recent studies of DR potential?

A7. No. The Commission may be tempted to set goals based on recent DR "potential" studies. However, these studies do not support setting goals at this time for several reasons. One is that they are typically focused only on peak load reduction. Another is that they generally do not focus on DR potential in California, but are more general.

One example is the National Assessment of Demand Response Potential, which focused entirely on peak load reduction.[3][4] National studies like this one

[3] National Assessment of Demand Response Potential, FERC Staff Report June 2009.

[4] A more recent FERC report found that California had DR responses exceeding five percent of load available in the CAISO balancing authority. (Assessment of Demand Response and Advanced Metering, FERC Staff Report, October 2013, at 11.) This includes both reliability-based and price-based DR. While it may appear lower than the amount of DR in other ISO/RTOs, the WECC requirements for DR are stricter than those of other NERC areas, and the Eastern ISO/RTOs are changing their requirements for DR.

often emphasize development of advanced metering and dynamic pricing options and well as traditional load-shedding DR.

Later in this testimony, I discuss other services that DR could provide beyond peak load reduction, which have been the subject of several recent potential studies, including flexibility and ancillary services. The Commission has expressed an interest in using DR for flexibility.[5] However, it is important to understand that these recent studies are at a very high conceptual level and do not support the establishment of goals at this time.

Q8. The Scoping Ruling asks for parties to provide recommendations for programs or activities to ensure equality for load modifying resources and supply resources and to suggest a definition for equality. (Scoping Ruling, Attachment A, at 1.) Do you have a recommendation on this matter?

A8. I am not sure what is meant by "equality". Both load modifying and supply resources should similarly affect resource adequacy (RA) requirements, either by reducing the load forecast on which the requirement is based or by meeting that requirement. Both types of DR are clearly valuable. The main difference is that one is integrated into the CAISO's markets and the other is not.[6] There should be no reason to require that existing DR programs be integrated into the CAISO markets and thus switch from load modifying to supply resources unless the criteria I have proposed (operational need and cost-effectiveness) are met.

III. Resource Adequacy Concerns (as directed by D.14-03-026)

Q9. The Scoping Memo raises a question about the use of DR for resource adequacy (RA) as follows:

---

[5] R. 13-09-011, at 12.
[6] D. 14-03-026, at 20.

- Parties should provide a detailed explanation of their resource adequacy concerns, specific to the bifurcation framework adopted in D.14-03-026). (Scoping Ruling, Attachment A, at 1-2)

What concerns, if any, do you have about this matter?

A9. The Commission decided in D. 14-03-026 that DR can help meet reliability needs as either a load modifying resource or a supply resource, although it relegated to this track the precise definition of those two categories. The decision states that the former reduces the load that defines the Resource Adequacy (RA) requirements, while the latter directly qualifies to meet those requirements.[7] Either way, DR affects resource requirements for RA. Either way, whether through reducing the load forecast[8] or through being a resource that can count for RA and meet requirements determined in the Long Term Procurement Plan (LTPP), DR can and should affect procurement requirements. The most important consideration is that DR be reflected in resource planning and RA compliance as well as daily load forecasts, whether as a load modifying resource or a supply resource. Failure to reflect DR's impact on load will result in over-procurement of resources.

IV. CAISO Market Integration Costs (as directed by D.14-03-026)

Q10. The Scoping Ruling raises a series of questions about the costs of integrating DR into the markets of the California Independent System Operator (CAISO). These are:

---

[7] D. 14-03-026, Ordering Paragraphs 1-3.

[8] I note later that the Demand Response Measurement and Evaluation Committee and the Demand Analysis Working Group will be addressing how to reflect the impact of DR on load forecasting, including the impact of dynamic pricing and TOU pricing, prior to the next IEPR demand forecast, which forms the basis for RA compliance and procurement. This is very important work since, unless the impacts of pricing changes on load are reflected in the load forecast, unnecessary supply resources will be procured.

- Parties should provide their understanding of the costs (in dollars) of the CAISO market participation either through their own direct participation or through the participation of other entities in other markets.
- Parties should present a range of costs that they would consider to be reasonable. Explain why this range of costs is reasonable and costs outside the range are not reasonable.
- For costs outside the range and therefore unreasonable, please provide examples of ways to decrease those costs.
- PG&E provided a list of solutions for decreasing CAISO market integration costs in its December 13, 2013 filing at page 13. Provide comments on the list of solutions. (Scoping Ruling, Attachment A, at 2.)

What is your testimony on this topic?

A10. I have no direct experience with bidding DR into CAISO markets. However, I have tracked the information available from the utilities and the CAISO on the experience of integration to date. I also attended the April 18, 2014 workshop on integration issues. While that workshop is not on the record, I provide my expert opinion herein on what was said at that workshop, as well as these other sources.

At the workshop the utilities indicated that they intend to bid some DR into the CAISO markets as a Proxy Demand Resource (PDR) this coming summer of 2014, either on a pilot basis or more broadly. These efforts will provide very useful information on the costs and challenges of integration. Unfortunately, this information will not be available in time to inform the record in this proceeding, given the current schedule.

There is some historical information available suggesting that the costs of integration of DR into CAISO markets may be significant. PG&E designed its PeakChoice program for the 2012-2014 DR program cycle to be able to be bid into the CAISO market as a PDR.[9] This increased the cost of the proposed program to the point that the Commission rejected it because it failed to meet cost-effectiveness requirements.[10] Thus, it is perfectly possible for integration costs to undermine the net benefit of integrating DR into the CAISO's markets.

As became clear at the April 18, 2014 workshop, the utilities and the CAISO recognize there are costs associated with integration that can have an impact on the cost-effectiveness of integrating DR into the CAISO's markets; they and other parties are attempting to find a solution. The CAISO expressed its willingness to consider various solutions. Unfortunately, there are numerous open issues but no timeline for their resolution.

A review of integration requirements and costs is essential to determine whether they are a significant impediment to cost-effective integration of DR as supply resources in the CAISO markets and whether these requirements can be changed in a way acceptable to both the CAISO and the Commission. I recommend that a workshop be convened after the summer of 2014 to review the costs of integration experienced by the utilities this year. A concerted effort should be made to reduce these costs in a timely manner. Widespread integration of DR resources should not occur until the costs of integration can be reduced to levels that do not render the DR programs cost-*in*effective.

---

[9] D. 12-4-045, at 113.
[10] D. 12-04-045, at 122-124.

Q11. Do you have any other concerns about integration of DR programs into the CAISO's markets?

A11. Yes, I do. My first additional concern is a technical one, i.e. the constraint imposed by the CAISO's requirement that a Demand Response Provider (DRP or aggregator) have an agreement with an LSE prior to registering a customer location served by that LSE.[11] Many customers participating in investor-owned utility (IOU or utility) reliability-based DR as well as price-based DR programs are direct access (DA) customers of energy service providers (ESPs). The impact of this provision is that the utilities will only be able to bid part of these programs into the CAISO markets unless they can reach these agreements with non-utility LSEs. For example, part of the load under the Base Interruptible Program (BIP) is expected to be bid into CAISO markets as a Reliability Demand Response Resource (RDRR) this summer and part (served by non-IOU LSEs who have not reached such agreements) likely will not. This is problematic because the operational requirements for DR bid into the CAISO and DR provided under the current utility agreement with the CAISO are not identical. Not only does this increase complexity, but it also will result in customers in the same program being treated differently. A similar issue arises with bidding DR in the Demand Bidding Program (DBP) into the CAISO markets as a PDR or a RDRR.

Q12. Do you have any other concerns?

A12. Yes. My second concern is a broader one. While the roles of the utilities and DRPs are important, it should not be forgotten that it is customers who provide

---

[11] "Distributed Energy Resources Integration, Summarizing the Challenges and Barriers", Olivine, Inc., January 2014, at 17.

the demand response. There are at least two factors that are important to customers relating to integration into the CAISO's markets. The first is the cost of integration that will be incurred by the customer providing DR, as well as the system-related costs. A key issue for the customer is its investment cost to respond to a DR event.[12] Customers can respond to a DR event signal either manually or through automation. For providing flexibility to facilitate grid integration of intermittent renewable generation, there has been much talk of automating the customer response. Automation is also required for provision of certain ancillary services (A/S). The customer response is only automated where there is either 1) direct load control (DLC), as in air conditioner cycling, or 2) receipt of an automated signal by a system pre-programmed to provide the response, such as an automated energy management system (EMS) or a programmable communicating thermostat (PCT).

Direct load control has only been used in California for air conditioner cycling. In other states it has been used to cycle electric water heaters, but use of electricity for domestic water heating in California is not common.

Equipment for an automated response, such as installation of an EMS system or a PCT, has a cost to the customer.[13] In the case of an industrial facility that is spread over a large campus, substantial internal wiring would be required for automation and the cost can be prohibitive. In addition, while many DR event signals are sent out by utilities on an automated basis, many

[12] As opposed to its opportunity cost.
[13] Utility incentive payments may be available for such equipment through the Technology Assistance/TechnologyIncentive program.

customers do not want to have to provide an automated response; further, many customers may not be able to provide an automated response. Many industrial customers may be required to provide a manual response because there are health and safety issues associated with giving up manual control of response that can be serious.[14] Their staffs may literally have to run around their facilities turning off switches by hand to avoid such risks. The challenges of manual response will be much greater and are likely to be prohibitive for such a customer to provide flexibility.[15] "Flexibility" events will likely occur more frequently and involve far more load adjustments than traditional DR.

Integration also has revenue implications for customers. If their loads are aggregated under contract to an IOU and are bid into the CAISO markets by a DRP, the aggregator must cover its costs and make a profit; this means the aggregator will have to take part of the revenue to do so. Larger customers do not need the facilitation of an aggregator to participate in DR and often prefer utility programs because they are not required to share the revenue. This is true for existing DR programs. Furthermore, prices for energy and non-spinning reserves (the two markets in which DR would have been able to participate until recently) in the CAISO's markets are far lower than tariff rates. Remuneration for providing those services would likely not be attractive enough to induce a customer to bid into those markets. For example, the

[14] Examples include electromagnets, cooling for heat transfer facilities, and dust suppression equipment.
[15] Of course, manual response will not be possible to provide regulation.

average price of non-spinning reserve in the CAISO markets in 2013 was $0.28/MW, equivalent to $2.45/kW-year.[16]

If we consider proposals for future DR that can provide flexibility or regulation, customers will likely expect significantly greater remuneration for more complex DR than they do at present, if they can provide these services at all. Since 2015 will be the first year with a flexible RA requirement, we do not know what premium will be available for providing flexibility.[17] However, given the amount of excess capacity in California, any such premium is likely to be inadequate compensation for the increased disruption of customer activities.

V. Supply Resources Issues

Q13. The next section of Attachment A to the Scoping Ruling addresses issues related to DR operating as a supply resource. The first questions go to the characteristics of existing DR programs that would be appropriately categorized as supply resources. What is your recommendation on this matter?

A13. A DR program should be a supply resource if it has the following characteristics. First, it should require CAISO dispatch in order for it to provide the service for which it is intended. For example, the CAISO must maintain required levels of ancillary services (A/S) and be able to dispatch the resources providing them to meet operating requirements (e.g. regulation) or contingencies (e.g. spinning reserves). Second, it should be cost-effective for the resource to be integrated into the CAISO's operations and markets. If the resource meets the first criterion but not the second, the Commission should work with the CAISO, IOUs, aggregators, and end users to find ways to make

[16] CAISO 2013 Annual Report on Market Issues and Performance, p. 145.
[17] Ideally, the schedule in this proceeding would be such that we would know this.

integration cost-effective. In the meantime, if it is cost-effective for the IOUs to dispatch the resource to meet their own or the CAISO's requirements without integration, this should happen with the DR program serving as a load modifying resource.

Q14. The Scoping Ruling then asks which existing DR programs should be classified as supply resources. Do you have a general response to this question?

A14. Recall that my two criteria are a requirement for dispatch by the CAISO and cost-effective integration. My preliminary assessment of services that can be provided by DR that would need to be dispatched by the CAISO are frequency regulation and flexibility (a service also sometimes referred to in the context of integration of intermittent renewables, and which may in the future include load following). I describe these services in greater detail below. The CAISO should also be able to call upon DR to provide other services, such as local reliability, mitigation of contingencies and frequency response; however, this could be done through the IOU or another DRP, as long as the DR is provided in an appropriate manner to meet the need. The latter services can be provided as load modifying resources with triggers tied to CAISO needs, as presently exist in the retail tariffs.

Q15. Is there any DR that is already slated for integration into the CAISO's markets?

A15. Yes. The Commission determined that reliability-based DR[18] should be integrated into CAISO markets when it adopted a settlement in D. 10-06-034. Reliability-based DR includes the Base Interruptible Program (BIP) and SCE's

---

[18] Also called emergency-based DR.

Agricultural Pumping Interruptible Program (AP-I). These programs provide a load reduction within either 15 or 30 minutes for system or local reliability services. They can be dispatched by the CAISO for system or local contingencies or by the IOUs for distribution-level contingencies like over-loaded substations. They are dispatched by the CAISO through the utilities. The CAISO notifies the utility and the utility notifies the customer.

BIP and AP-I will be able to be bid into the CAISO markets as a Reliability Demand Response Resource (RDRR).[19] RDRR allows resources providing reliability-based DR to bid energy into the day-ahead market, accommodating dual participation by such resources in the Demand Bidding Program (DBP). RDRR also allows such DR to be dispatched in real-time by the CAISO pursuant to its Operating Procedure 4420, after it issues a Warning or in case of a Transmission Emergency. Once RDRR is dispatched, it enters a bid price into the CAISO real-time market of $950/MWh; RDRR's bid price then sets the price for all resources dispatched up and down in the real-time market during those intervals when RDRR is dispatched.

In 2010, when the integration decision was made, the costs of integration were not known. I am not recommending that this decision be revisited. Rather, I am simply pointing out that the cost of integration is a factor that should be taken into account when deciding which DR to integrate in the future.

There is currently a limit on reliability-based DR of two percent of peak

---

[19] This ability to bid is subject to LSE permission to bid as discussed earlier.

CAISO demand.[20] Thus, absent a change in the settlement, there is little room for expansion of this type of DR, despite its demonstrated value and its imminent integration into the CAISO markets.

While reliability-based DR is not used frequently, it provides significant benefits when called upon.[21] The most recent example was on February 6, 2014. On that cold February day, BIP was used to reduce load in the face of a shortage of generation resources that resulted from limited natural gas supplies, as opposed to high overall system demand. Similar interruptible load programs were used extensively to address generation shortages during the Energy Crisis in late 2000 and early 2001.

Q16. When will reliability-based DR be able to be bid into the CAISO's markets?

A16. The CAISO tariff change to integrate reliability-based DR as RDRR into its markets has been approved by the Federal Energy Regulatory Commission and became effective May 1, 2014.

Q17. Please describe other categories of DR that should be treated as supply resources.

A17. For the purposes of treatment as supply resources, the emphasis should be on possible future DR programs, rather than current ones. As noted above, the use of DR for flexibility or ancillary services clearly requires CAISO integration. These are also new uses of DR. Existing DR programs do not inherently require such integration.

Q18. Please describe such new uses of possible future DR programs.

---

[20] D. 10-06-034, Attachment, at 6.

[21] It is also tested annually.

A18. I will begin with the proposal to use DR as flexible load to integrate increasing amount of intermittent renewable generation. Some studies have called this the provision of flexibility per se whereas others have characterized this as a form of ancillary service. Thus both characterizations are used, often interchangeably. The Commission expressed interest in using DR for this service in this rulemaking.[22]

DR for flexibility service is a new concept and would involve a market product that can be ramped up and down and can follow load. It would have to meet the requirement for flexible RA that is scheduled to go into effect for the 2015 RA compliance year. Under the ISO's Flexible Resource Adequacy Criteria-Must Offer Obligation (FRAC-MOO decision), such DR will have to be bid into the CAISO markets. The CAISO has decided that DR can provide flexible RA if it has the following characteristics.

- It must be bid into the CAISO markets for at least five hours per day on weekdays.
- It must be able to provide energy at an Effective Flexible Capacity level for at least three hours.
- It cannot comprise more than five percent of the Load Serving Entity's total flexible capacity requirement each month.

In order to meet these flexibility requirements, load would have to be adjusted far more frequently and with shorter notification that under current DR programs.

[22] Rulemaking 13-09-011, at 8.

While conceptually DR can provide flexibility, there is very limited experience with implementation and there are challenges in aggregating loads to provide the required capability. The Lawrence Berkeley National Laboratory (LBNL) recently completed a study that stated:

> The concept of "flexible demand" has generated significant interest but *is still in the early developmental stages*. The topic has been *qualitatively* explored through studies by organizations such as Lawrence Berkeley National Lab (LBNL), the National Renewable Energy Laboratory (NREL), the Demand Response Research Center (DRRC), the California Public Utilities Commission (CPUC), GE Energy, EnerNOC, and others. These studies have focused primarily on the *theoretical* capabilities of DR to integrate renewables, the types of load that may be good candidates to provide such services, barriers that are preventing DR from being utilized in this manner, and policy recommendations for overcoming these barriers. In addition, a few demonstration projects have tested the actual capability of loads to be controlled in order to provide ancillary services that are needed to address the challenges of renewables integration. For example, Mason County Public Utility District #3, in partnership with Bonneville Power Administration (BPA), tested the ability to increase or decrease water heating load with short response time through direct control of the water heater in 100 homes in Northwestern Washington (Mason Country PUD 3, 2012). Operation of the water heater was tied directly to the output of wind units on BPA's system, to time the load changes to coincide with periods when wind generation was ramping up or down. While these studies suggest that there is *potential* for DR to be used to integrate renewables, the concept *has not yet been tested on a large scale.*[23]

This study makes it clear that the use of DR for flexibility is still at the conceptual and pilot stage and should not be assumed to be ready for widespread usage.

A Navigant study for the Demand Response Measurement and Evaluation Committee concluded the following:

> Despite the apparent inability of the existing IOU DR program portfolio to

[23] "Analytical Frameworks to Incorporate Demand Response in Long-Term Procurement Planning", LBNL 6546-E, Satchwell, A. and Hledik, R., September 2013, at 14 (emphasis added).

> meet CAISO grid management ancillary product requirements, there are modifications to certain programs that would increase their ability to provide products with the technical attributes required for certain ancillary services. In general, the most important program improvements that would be required in order for a DR program to be used by the CAISO in managing the stability of the grid include:
>
> » Use of telemetry for real-time communications, metering, and control;
> » Reduced notification time;
> » Automated response to control signals; and
> » Increasing the number of times and frequency with which the program could be dispatched.
>
> Some of those modifications might significantly reduce the number of customers willing or able to participate in that DR program. Other changes would fundamentally alter the nature of the program or be incompatible with the design of that program.[24]

While this study finds that current programs may be able to be modified through the use of telemetry and automation to be used for renewable integration, Navigant did not analyze the cost of doing so. The Commission has appropriately asked for information about such costs in this proceeding. Without such cost information, the appropriateness of using DR for this purpose is at best uncertain.

In addition, the Navigant study points out that there is the critical issue of whether customers will tolerate having their loads adjusted far more frequently to provide this service. Under the existing DR programs, certain customers have agreed to reduce their loads for reliability reasons and others have agreed to do so on the basis of price[25] and reliability. However, utility monthly reports demonstrate that the number of times these programs are

---

[24] Potential Role of Demand Response Resources in Integrating Variable Renewable Energy under California's 33 Percent Renewables Portfolio Standard July 20, 2012, at 1-17.
[25] The "prices" are actually derived from proxies for price like heat rates and temperature.

dispatched, and thus that load is reduced, vary, but do not exceed 30 times per year; this level of dispatch is manageable for the customers participating in the programs (if it were not manageable, they would not participate).[26] From the industrial customer perspective, using DR to ramp up and down or provide regulation or to integrate renewables will be very different. It will require many more dispatches, perhaps even daily, with more disruption and wear and tear on equipment. Customers who currently provide DR are likely to react with reduced interest or require significantly higher remuneration for participating or both. Perhaps large aggregations of new customers from the residential or commercial classes could be used for this purpose as they have smaller loads that could be dispatched in more flexible blocks. From a general ratepayer perspective, there will be the costs of higher payments to participants and investments in automation, in addition to the costs of integration into the CAISO markets. These costs and technology requirements must be taken into account in assessing whether DR can and should perform this function. It is premature to even consider setting goals for DR to provide flexibility until this is done, and until the methods for using DR for flexibility are further developed. Furthermore, not all loads, perhaps not many loads, are capable of providing the type of flexibility the CAISO is seeking, so the potential to provide this service is quite uncertain. It would be premature to attempt to set any goals for it.

[26] SCE CBP, day-ahead over three different time intervals. All other programs were called less frequently for all 3 utilities. (SCE dec 2013 Monthly ILP Report for December 2013 .pdf)

Q19. Are there any more studies of the use of DR for flexibility that provide useful information?

A19. There are several more recent studies of the use of DR for flexibility that I summarize here. As indicated, their suitability for use as a basis for any policy decisions is highly questionable.

Another recent LBNL study focuses on using non-industrial loads for ancillary services and flexibility as well as traditional reliability-based DR. It looks at possible uses of residential, commercial, municipal (water and waste water pumping) and non-manufacturing industrial loads (data centers, agricultural pumping, and refrigerated warehouses) to provide DR.[27] This study attempts to incorporate the dispatch of DR from these end uses in a production cost model for renewable integration in the Western Interconnection. While the study identifies possible end uses to target for DR, the presence and amounts of these end uses vary greatly by location within the Western Interconnection and some are not applicable to California. For example, electric heating and water heating are rare in California, while air conditioning is seasonal and may not operate during the periods of highest flexibility need (which are not during the summer). LBNL finds potential for flexibility or regulation mainly from residential air conditioning and commercial lighting in Colorado, the state it studied. The former is only available on a seasonal basis and the latter is not a large load.[28] Thus, while this study is useful, it is not sufficiently definitive to be used to set any goals for DR to

---

[27] Grid integration of Aggregated Demand Response, Part 2: Modeling Demand Response in a Production Cost Model, NREL/TP-6A20-58492 December 2013.
[28] Id., at viii.

provide flexibility in California at this time.

There is also a recent study by Oak Ridge National Laboratory that considers whether and to what extent industrial load can provide various forms of DR, including energy, capacity, ancillary services, and flexibility.[29] As a long-time consultant to industrial consumers, I find that this study is very preliminary and based on insufficient and problematic data. Its use of two-digit SIC codes is problematic because of the degree of aggregation, especially given that the sample sizes are very limited.[30] The study does not even consider industrial gases, likely one of the most flexible industrial processes. Furthermore, the study notes that frequent starts and stops of equipment can be damaging but then concludes that facilities with such equipment can provide regulation or flexibility. (Op. Cit., at. 47) Thus, the technical potential conclusions and availability conclusions of the study are suspect and should not be used to conclude that there are thousands of MW of potential flexibility from industrial facilities in California.[31]

Q20. You mentioned the use of DR to provide ancillary services. Is there much experience with DR used for this purpose?

A20. Yes. Ancillary services are well defined and can be self-provided or procured in the CAISO markets. DR providing A/S would have to be integrated into those

[29] "Assessment of Industrial Load for Demand Response across U. S. Regions of the Western Interconnect" ORNL/TM-2013/407, September 2013.
[30] For example, for SIC 32, which is used as an example, a single load shape is shown on pages 27 and 28 that is said to be representative of the SIC code. However, the load shape is for plate glass, which is very different than the one for cement, although both are in the same two-digit SIC code. In addition, the sample sizes are very limited. For example, the sample of plants used in the study for SIC 32 is 3%, which is highly unlikely to be a representative sample, especially given the mix of industries.
[31] As it does on page 47.

CAISO markets in order to be dispatched for operational reasons or to meet contingencies. Thus DR providing A/S would have to be a supply resource. DR has provided all A/S, including non-spinning reserve, spinning reserve, and regulation in balancing areas of Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) outside of California. For example, DR provides half of the spinning reserves in ERCOT.[32] Unlike the situation in other parts of the country, in the Western Interconnection, including California, the Western Electricity Coordinating Council (WECC) only recently received approval from FERC to change its rules to allow DR to provide spinning reserve or regulation.

There are a few challenges, however, in using DR for A/S, particularly regulation.[33] The first is that A/S are dispatched on a five-minute basis, so the end use loads providing the DR must be able to be varied in small increments, rather than being turned either on or off.[34]

Second, because A/S would be provided under the CAISO's PDR, there is a problem with bidding discrete loads. If a load offers a load drop of 3 MW based on the ability to stop using one piece of equipment, it may be the marginal offer and the CAISO may only accept 1 MW. In this case the load will provide more than the amount required and will be exposed to penalties and uninstructed energy charges. Under such circumstances, the customer would

32 "Load Participation in Ancillary Services", DOE, December 2011, p. 11.
33 Actually, this problem also occurs when bidding energy into the CAISO markets under PDR.
34 This is the reason that large aggregations of small loads, like air conditioning load, have been considered a possibility to provide such services, but these run into difficulties with requirements like telemetry.

most likely find the risk of bidding in its load too great.

Third, particularly for regulation, the equipment being used to adjust load must be able to survive frequent changes in its operation without damaging it or unduly disrupting the customer's business.

Fourth, market prices have been too low to support DR provision of ancillary services in California, particularly non-spinning reserve. In addition, telemetry is required to provide A/S, and the cost of required telemetry has been significant. For more DR to participate in these A/S markets, lower-cost telemetry or an alternative must be developed. Also, automated response would most likely be required, with its attendant costs.

Thus, while DR can be used for providing A/S, there are unanswered questions in terms of costs and viability on any scale. I would deem it premature to set goals for DR participation in these markets. Loads that can provide these services would have to be identified, aggregated, and have cost-effective telemetry options.

VI. Demand Response Auction Mechanism (DRAM)

Q21. The Scoping Ruling asks parties to provide comments on a proposal included in Attachment B for a Demand Response Auction Mechanism (DRAM). It contains several questions about the operation of the auction mechanism. Do you have a response to this proposal?

A21. This proposal is for an auction mechanism to procure some amount of DR in the future, although it is not entirely clear whether it is to be all DR or only incremental DR. Attachment B states:

> Bidders are prohibited from scheduling actual DRAM deliveries from the same customers as another bidder, *or those that are current participants in a utility demand response program*. Thus, *all capacity bids must be for unique*

> *resources that are additional and incremental to existing utility baselines*, unless the bidder demonstrates that the customer(s) has(ve) disenrolled from the applicable utility program, or have committed to disenroll by the commencement date of the contract. (Scoping Ruling, Attachment B, at 10, emphasis added)

I would interpret this as meaning that DR up to current levels in utility DR programs would continue to be procured without going through the auction and that only incremental DR would be procured through the auction. If this is the case, I would conclude that DR programs covered by bridge funding would not be bid into the CAISO markets for 2015 or 2016, since the bridge funding is designed to maintain current levels of DR. This interpretation appeared to be confirmed at the April 28, 2014 workshop. If this interpretation is not correct, then the Scoping Ruling is not clear, nor is the concept of bridge funding. The Scoping Ruling is also unclear as to whether the auction would be used to procure only incremental DR or part of the DR currently covered by existing utility programs beginning in 2017.

Q22. Are there elements of the DRAM proposal that are unclear or that require assumptions in order to address them in testimony?

A22. Yes. Before answering some of the detailed questions about the structure of the proposed DR auction posed by the Scoping Ruling, there are numerous threshold questions that must be answered, or at least assumptions that must be made. For non-reliability-based DR, the Scoping Ruling proposes an auction with offers ranked on the basis of capacity prices and fulfillment of various RA needs (system, local, and flexible). I had assumed that it was the proposal's intent to rank offers for providing each type of RA differently and then procure these different services separately based on the offer prices for each. However, based on discussions at the April 28 workshop, it appears that this is not the intent. Rather, it appears that the intent is that all the offers would be ranked together, regardless of the service provided. The concern expressed by staff was that otherwise there could be insufficient offers for a competitive auction.

If it is correct that the intent is that all of the offers would be ranked together, I do not see how the offers can be suitably ranked based on prices for three services at the same time. There is no clear way that I can see to weight the offers for the services offered. In the Renewable Auction Mechanism, bids can be weighted by the hours of delivery. However, there is no clear basis for establishing the relative value of the three different types of RA service. If the Commission were to decide to pursue such an auction, a great deal of attention (and time) would have to be paid to determine such "details".

There are also questions about how auction winners will be compensated. It appears DR offers that win in the auction will only be paid for capacity and that this capacity price will not come from the CAISO markets; rather, it will come from the utilities. The Scoping Ruling is not clear as to how the winning DR would be offered into the CAISO markets for energy and ancillary services and at what price, or who would receive the revenue from these CAISO markets. At the workshop, staff said that while the winning DR would receive capacity payments from the auction, it would have full discretion to offer into either the energy or ancillary service markets of the CAISO at any price up to the offer cap, as long as it met must-offer obligations.[35] If it is offered in at high prices, would the CAISO attempt to mitigate the bids, as it does for generation, i.e. would it attempt to limit bidding to the resource's marginal cost?[36] This would be a significant impediment.

For current price-based DR programs, there are other questions. If the auction applies only to new or incremental DR, will customers enrolled in existing programs be paid the tariffed incentive while new customers in the same programs are paid under the auction? Furthermore, the Commission should seriously consider this point: if customers did not choose to participate in existing tariffed programs at fixed incentives, why would they compete to provide DR at potentially lower payments in a competitive auction?

Q23. Do you have a reaction to the proposal to accept offers on a "pay-as-bid" basis?

A23. Yes. It is my understanding that the Electricity Reliability Council of Texas (ERCOT) balancing authority has an auction for reliability-based DR that uses an RFP for procurement subject to a price cap and a maximum budget. There, the highest accepted offer sets a market-clearing price for all accepted offers. [37] Eastern ISO/RTOs also use a market-clearing price. I am not aware of any competitive procurement of DR that uses a "pay-as-bid" format. If it is the intention of the staff proposal to reduce costs by only paying what is bid, rather than a market-clearing price, I believe that this may be problematic. First of all,

---

[35] It is important to note here that PJM does not subject DR to must-offer obligations. The matter is under review at present in PJM and is highly contested. [ER13-2108.]

[36] Of course, it is not clear what the marginal cost would be for a DR resource and there is little literature and no information on opportunity costs.

[37] ERCOT Emergency Response Service Procurement Methodology 050114.doc

there has been a debate for many years as to whether prices are lower under pay-as-bid vs. market-clearing price auctions. Second, as discussed elsewhere in this testimony, there is no sound basis for assuming that DR offered into CAISO markets will accept lower prices than DR providing current services that are simpler and less intrusive for the customer. The sole purpose of renewables bid into the RAM is to sell kWh, and each bidder knows its cost structure and will not bid in at a price that does not cover its costs and profit margin. However, customers providing DR are doing so as a subsidiary activity to their primary focus: their regular daily operations. Consequently, they are unlikely to aggressively compete on price in order to provide a service that will disrupt their primary business.

Q24. The Scoping Ruling sets goals for procurement of price-based DR through the DRAM as follows:

> Each utility will be required to procure a minimum amount of price responsive demand response and be expressed as a minimum percentage of total system peak for the appropriate year, and procured as part of their system, local and flexible resource adequacy requirements. This is the DRAM procurement obligation. Price-responsive demand response capacity comprises about 2.5 percent of maximum utility system peak load in 2014. With this as the starting point, the aim is to reach a total procurement target for price-responsive demand response in 2020 of 5 percent of peak load for each utility on a service territory basis. The annual target for price-responsive demand response will increase incrementally from 2016 onward, at the following percentages: 3 percent in 2016, 3.5 percent in 2017, 4 percent in 2018; 4.5 percent in 2019; 5 percent in 2020 and in each year thereafter, unless and until another target is adopted. (Scoping Ruling, Attachment B, at 7.)

What is your recommendation with respect to this proposal?

A24. I believe that it is at best premature. As I indicated in my testimony on goals, there is presently no basis for setting goals for procurement of any price-responsive DR. This proposal sets very specific goals for procurement of DR through the DRAM, regardless of the services the DR might provide, and regardless of the cost of providing the service or of integrating it into the CAISO markets.

Elsewhere in the proposal there is a mention of a cost cap. While I address this matter is some detail later, basing a cap only on offers to provide DR without considering other resource procurement would be no substitute for a cost-effectiveness analysis.

The staff mentioned at the April 28 workshop that upcoming proposed changes to the current retail cost-effectiveness methodology would be used to evaluate the offers, although this is not mentioned in the Scoping Ruling. The use of a cost-effectiveness test could mitigate the problem of comparing DR offers to each other. Unfortunately, no information has been provided as to how such a test would be used, and we have not seen the proposed revisions to the cost-effectiveness methodology. Accordingly, it is very difficult – if not impossible - to provide testimony on the impact the use of this methodology for this purpose would have.

Given that the questions in the Ruling discuss achieving a *minimum* amount of DR through this mechanism, the question that naturally follows is this: if the offers are higher than the cost cap or do not meet some yet-to-be described cost-effectiveness test, is the procurement requirement to be met anyway? At the April 28 workshop, the staff stated that the goals would not be binding on the utilities if the prices exceeded the cost cap, despite the reference to minimum procurement levels. However, since the averaged cap is problematic (as discussed below) and since there is such a strong emphasis on goals in the early part of the Scoping Ruling, including the explicit goals proposed for the DRAM, the precise intention with respect to goals is far from clear.

Q25. The Scoping Ruling asks for specific recommendations on the following approach: "Emergency demand response resources are included in the DRAM, which means that these resources must receive their capacity payments via a competitive mechanism." (Scoping Ruling, Attachment A, at 4.)

A25. With respect to reliability-based DR programs, I conclude that there is no good reason for reliability-based DR to be included in the DRAM. There is a cap on the amount of reliability-based DR, as acknowledged in Attachment B to the Scoping Ruling at page 10. The cap is set at 2% of peak CAISO load, allocated in the settlement adopted in D. 10-06-034 to the three largest IOUs. If a utility has reached its cap, the language on page 10 referring to incremental procurement suggests that the auction would only apply to incremental reliability-based DR associated with a future higher peak or to replacement reliability-based DR. If a utility has not reached its cap, why should existing reliability-based DR be procured under the tariff and incremental reliability-based DR be procured under the auction? Customers wishing to participate in these reliability-based DR programs could have signed up under the existing tariff. It is hard to understand why customers would bid into an auction to provide a service that they decided not to provide under the tariff unless they were to bid at a significantly higher price that the tariff allows. If the intention is to use competition to lower prices/incentives, this seems doomed to failure. There is certainly no reason to expect that there is pent-up demand to participate in reliability-based DR programs that have been around for decades, unless it is at a higher price or incentive level.

Q26. Attachment B of the Scoping Ruling says:

> "Public Utilities Code 454.9(b)(9)(C) states "(T)he electrical corporation shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible," thus DRAM procurement must be cost-effective. The DRAM is designed to meet this requirement, as bids are selected consistent with least-cost principles. Demand response resources that bid into CAISO wholesale electricity markets are also required to meet wholesale cost-effectiveness standards. For capacity, all DRAM auctions, and resultant awards, would be subject to a capacity price cap specific to that auction." (Scoping Ruling, Attachment B, at 6)

Does this construct assure cost-effectiveness?

A26. No. Selecting bids based on least-cost principles among a set of DR-only offers does not assure that the bids are cost-effective per se. There is no cost-effectiveness analysis proposed based on avoided or deferred costs of generation, transmission or distribution in the DRAM proposal.[38]

In addition, the above quotation refers to meeting "wholesale cost-effectiveness standards". There are no such standards. It is my understanding that the language cited above refers to the Net Benefits Test (NBT) adopted in FERC's Order 745. While that order does refer to "cost-effectiveness", it is in a different context. The cost-effectiveness test referenced in the Scoping Ruling should relate to the entire cost of the DR, including capacity and energy payments, integration costs, etc., compared with the avoided costs of

[38] I am encouraged that we were told at the April 28 workshop that there will be some cost-effectiveness analysis separate from the ranking of the offers in the DRAM, but it is not possible to address it without more information on how this will occur.

generation, transmission, and distribution. The NBT only relates to impacts on the *energy* price paid by load in an ISO/RTO's energy markets if winning DR resources do not pay for the power not taken. Order 745 states:

> Consistent with this finding, this Final Rule adds section 35.28(g)(1)(v) to the Commission's regulations to establish a specific compensation approach for demand response resources participating in the organized wholesale energy markets administered by RTOs and ISOs. The Commission is not requiring the use of this compensation approach when demand response resources do not satisfy the capability and cost-effectiveness conditions noted above.
>
> This cost-effectiveness condition, as determined by the net benefits test described herein, recognizes that, depending on the change in LMP relative to the size of the energy market, dispatching demand response resources may result in an increased cost per unit ($/MWh) to the remaining wholesale load associated with the decreased amount of load paying the bill. This is the case because customers are billed for energy based on the units, MWh, of electricity consumed. We refer to this potential result as the billing unit effect of dispatching demand response. By contrast, dispatching generation resources does not produce this billing unit effect because it does not result in a decrease of load. To address this billing unit effect, the Commission in this Final Rule requires the use of the net benefits test described herein to ensure that the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources. When the net benefits test described herein is satisfied and the demand response resource clears in the RTO's or ISO's economic dispatch, the demand response resource is a cost-effective alternative to generation resources for balancing supply and demand.[39]

Thus, the purpose of the NBT is entirely different. The NBT is to determine when DR bidding into an ISO/RTO market will result in a lower market-clearing price (locational marginal price or LMP) *for energy* that more than offsets the impact on the remaining load that is paying LMP for the DR; this occurs if the LMP exceeds a calculated threshold level.[40] The use of the NBT is clearly not a

---

[39] FERC Order 745, 134 FERC ¶ 61,187, March 15, 2011, at 3-4.
[40] "The second condition is that the payment of LMP for the provision of the service by the demand response resource must be cost-effective, as determined by the net benefits test described herein.

cost-effectiveness test that is relevant to a decision to procure DR resources at some capacity price compared to other resources.

Q27. The Scoping Ruling also discusses a cost cap based on offers into the DRAM. Attachment B says:

> To ensure cost-effectiveness of demand response capacity procured under the DRAM, capacity cost caps will be calculated based on bids received for each auction. Each utility shall bear responsibility for calculating the capacity cost cap specific to its service territory and auction. The capacity cost cap shall be calculated immediately following each auction. For price-responsive demand response, the capacity cost cap will be an average of the capacity bids received in that auction for system, local and flexible demand response products. A separate cost cap will be established for emergency-triggered demand response resources, and will also be the average of bids received for those resources. For both categories of resources, disproportionately high bids shall be eliminated for purposes of calculating the cost cap. (Scoping Memo, Attachment B, at 6.)

What is your response to the capacity cost cap proposal?

A27. I see no basis for setting a cap at the average of the capacity bids received for different services that will impose different costs and make different demands on the provider. If offers reflect costs to providers, such averaging would likely under-compensate those providing more complex and frequent services. It is

---

With respect to the second cost-effectiveness condition, the record leads us to alter the proposal set forth in the NOPR in this proceeding. As various commenters explain, dispatching demand response resources may result in an increased cost per unit to load associated with the decreased amount of load paying the bill, depending on the change in LMP relative to the size of the energy market. As stated above, this is the billing unit effect of dispatching demand response resources. However, when reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such a payment is a cost-effective purchase from the customers' standpoint. In comparison, when wholesale energy market customers pay a reduced price attributable to demand response that does not reduce total costs to customers more than the costs of paying LMP to the demand response dispatched, customers suffer a net loss. Implementation of the net benefits test described herein will allow each RTO or ISO to distinguish between these situations." (FERC Order 745, 134 FERC ¶ 61,187, March 15, 2011,at 40-41. Footnotes omitted.)

also not clear how "disproportionately high bids" would be defined. As I have indicated earlier, there is a significant likelihood that the offers will be in excess of the current tariff incentive levels, since the current programs are not over-subscribed in general at current tariff incentives. In the case of the use of DR for other services, like flexibility or ancillary services, these future DR programs are likely to be significantly more demanding of customers, strongly suggesting that they will require increased compensation. On what basis would such bids be deemed "disproportionately high"? If all of the bids are at or in excess of the tariff rate, the average would be the same as the tariff rate or higher. ED staff stated at the April 28 workshop that the utilities would not have to meet procurement goals if prices were too high; it is hard to imagine, however, that the Commission would order the utilities to reject most or all such bids if there were adopted procurement goals.

Q28. The Scoping Ruling asks if DRAM contracts of one to three years or longer are desirable. What is your response?

A28. Most current utility DR programs require a one-year commitment from the customer. Reliability-based DR programs have an annual opt-out window in November so that if the terms and conditions or incentive level of a program change significantly, a customer can decide whether or not to stay on the program. This is extremely important to customers, since they determine whether or not to participate by comparing the value of the compensation they receive for participating against the disruption of their operations caused by DR programs when they are dispatched. As an indication of how important this annual review is for customers, the 2010 settlement included a separate opt-out window for customers to respond to the changes in when reliability-based DR could be triggered under the settlement compared to the prior terms and conditions. The industrial customers I know would be very concerned about making a multi-year commitment to provide DR if the terms and conditions were subject to change over the period of the commitment. They would also be very concerned about such a commitment if the remuneration for response were uncertain over the commitment period. Indeed, this uncertainty would place ongoing participation at risk.

Furthermore, making a multi-year commitment that would begin at some point in the future, e.g. a year or two ahead, would also be very problematic for an industrial company. No company can commit to staying in business in order to be able to provide a load drop for an extended period of time. An aggregator may be willing to undertake a multi-year commitment that allows it to add and subtract customers over time, but this would be considerably more problematic for an individual customer.

Q29. What is your overall assessment of the DRAM proposal?

A29. My general assessment is that while I do not object to using an auction in the future to procure some amount of DR, and while I applaud the staff for its creativity, the proposal presented in Attachment B raises many questions and is unlikely to be viable without further discussion and changes. My testimony has discussed some of the problems with the proposal. I would recommend that the Commission not adopt an auction without an opportunity for parties to come together to see if they can jointly address these problems and arrive at a mechanism with a greater probability of success.

Q30. The Scoping Ruling asks:

> "This proposal currently envisions Commission-regulated utilities procuring DRAM capacity on behalf of their own load, and does not include a procurement obligation for other Load Sharing Entities. Comment on whether other Load sharing entities should also have a procurement obligation for DRAM capacity and, if so, how such procurement should be structured. Be as specific as possible." (Scoping Ruling, Attachment A, at 4.)

What is your response?

A30. Non-utility LSEs are under no obligation to do their own DR procurement, whether load modifying or as a supply resource to be integrated with the CAISO. The Commission has no authority to require them to procure DR or to do so under the DRAM. However, while they have no obligation to procure DR, they could voluntarily participate in a utility-run auction if the Commission allowed this.

Q31. The Scoping Ruling asks:

> In D.14-03-026, the Commission discusses its policy of increasing the amount of demand response integrated into the CAISO market. Provide your thoughts on how we can determine an appropriate annual goal for overall demand response integrated into the CAISO market. Are there terms that we need to identify and define? What should those terms and definitions be? (Scoping Ruling, Attachment A, at 4)

A31. As I have indicated in my testimony on the various services that DR can provide as supply resources, it is premature to set a goal for DR's participation at this point on either a service-by-service basis or an aggregated basis. There is insufficient information on viability, in the case of flexibility, or costs for any of the services. No decision on goals should be made before these factors are further illuminated by 1) the bidding of some DR into CAISO markets this summer (2014) and 2) the results of the CAISO's efforts to reduce integration costs as discussed earlier.

Q32. The Scoping Ruling asks:

> "Do we need to improve forecasting with regard to supply resources that will be integrated into the CAISO energy markets? What are methods to improve the forecasting? What are methods that the Commission can use to modify current demand response programs to meet forecasted needs? What are methods that the Commission can use to design new programs to meet forecasting needs?" (Scoping Ruling, Attachment A, at 4)

A32. There are potentially two questions here. The first is how much DR is likely to be integrated. As I have indicated, this should be a function of the cost and benefit of such integration, which is hard to predict without more information on integration costs. The second is the forecast of the load impact for the integrated DR under different circumstances. The latter will be informed by the actual load reductions achieved in the CAISO markets. These can be estimated through the load impact protocols on an ex ante basis and measured through metering and, if appropriate, telemetry data.

The question of how the Commission can modify current DR programs to meet forecasted needs presumes that there is an explicit forecasted need for DR. I am not sure what the basis for that presumption would be at this point. It could conceptually be based on an analysis of how much DR could be cost-effectively employed to provide certain services and on a realistic assessment of how much of DR is likely to materialize. The first should be informed by more data on the cost of integration. The second will depend on customer willingness to participate, which in turn will depend on the level of compensation that is available and the nature of any business disruption involved in providing the DR.

Q33. The Scoping Ruling asks:

> D.12-04-045 discussed the future of demand response and questioned what the roles of the utilities and third party providers would be in administering future programs. We look at the roles of utilities and third party providers in administering supply resources. Provide your comments on whether a utility centric model for supply resource demand response can meet current and future needs. Provide your comments on the ability of third-party providers to provide supply resource demand response to meet current and future needs.
> As discussed in D.12-04-045, should the Utilities continue to offer rate regulated supply resource demand response if these services are provided through competitive markets? Should the Commission focus on identifying more of these programs as supply resources, thus facilitating broader competition in the market? Should the utilities' role be solely to oversee the competitive procurement? (Scoping Ruling, Attachment A, at 5.)

A33. Until the adoption of Rule 24, which sets the terms and conditions under which retail load of Commission-regulated utilities can be bid into the CAISO markets, the utilities were the sole avenue for providing funding for DR programs, whether directly to participating customers or to aggregators of the loads of those customers. Even with Rule 24, the revenue for DR programs from the CAISO's wholesale markets will be compensation for providing energy and A/S at prices that are not likely to be sufficient to encourage DR to participate or support aggregator business models. Indeed, the prices in the CAISO energy and A/S markets are low compared to those in other markets.[41]

Capacity payments for DR will still be required. They have come from the utilities and would have to continue to do so absent a capacity market at the

---

[41] Demand Response Providing Ancillary Services: A Comparison of Opportunities and Challenges in U.S. Wholesale Markets", Cappers et al,Grid-Interop Forum 2012. at. 3.

CAISO. Even if there were such a capacity market, which we do not support, it might not produce prices that would be sufficient to incentivize incremental DR. Certainly, current prices in the bilateral RA market for generation are well below the cost of new entry due to excess capacity, recently being in the range of $38-44/kW-year.[42] It is not clear whether the introduction of a flexible RA requirement in 2015 will lead to higher prices for flexible RA compared to standard RA products (or whether DR can provide this flexibility). These RA capacity payments may also be insufficient to support incremental DR. Indeed, I assume that this is a reason why the Scoping Ruling includes the DRAM proposal as a source of capacity payments for DR. Since the utilities would be the conduit for the DRAM revenue, the utilities would still be central to the DR market.

I do not see a reason to prevent utilities from continuing to run DR programs for retail customers. Both utilities and third parties should be able to provide DR services in the future, and customers should be able to choose which type of program is of greater benefit to them. If customers are content with existing utility DR programs, and if these programs are cost-effective and provide value, I do not see a reason to require customers to switch to third party DR programs.

If utilities were to be denied the ability to directly provide an opportunity for their customers to engage in DR, the Commission should not assume that all customers on existing utility DR programs would flock to third

[42] CPUC 2012 RA report, at 23.

parties. As I stated earlier, for many large customers, at least, one reason is that the customers do not require the assistance of an aggregator to provide DR. Another is that they do not wish to share the remuneration for providing DR with a third party. My clients prefer utility DR programs and have been participating for decades. Third parties may have an important role to play in "aggregating" the loads of numerous smaller customers to provide services, either to the utility or the CAISO.

The Commission should certainly *not* identify more DR programs as supply resources to foster competition. DR programs should be identified as supply resources where this makes sense using the criteria discussed above, namely the need for CAISO dispatch and cost-effectiveness.

VII. Load Modifying Programs

Q34. The Scoping Ruling asks parties to address the characteristics of load modifying DR resources. Do you have a proposal?

A34. Yes. There are two potential "sets of characteristics" for load modifying resources. One is essentially pricing-oriented, and would include responses to dynamic pricing tariffs. The other may be characterized as the more traditional type of non-price-based DR that has not been integrated into CAISO markets in the past. If that DR does not *need* to be dispatched by the CAISO operationally, it should be another subset of load modifying DR.[43]

[43] An example of a service provided by DR that does not need to be integrated into the CAISO markets and could be treated as a load modifying resource is frequency response. This is an automated response to a mismatch of loads and resources that leads to a divergence of system frequency from 60 Hz. The low frequency limit for the WECC is 59.5 Hz. High-speed DR can shed load to bring frequency back within the appropriate range if there is an under-frequency event. This service is automated through the use of under-

The challenge is that there is a third type of DR that is not cost-effective to integrate into CAISO markets but would ideally be or should be dispatched by the CAISO for operational purposes. Here, the logical solution is that a concerted effort be made to reduce integration costs. In the meantime, I would propose that the Commission refrain from classifying this DR a supply resource and requiring it to be bid into ISO markets at uncertain and perhaps prohibitive cost. Instead, I would recommend that the Commission do all it can to encourage adoption of integration requirements that are lower in cost and make integration cost-effective and only then require such DR to be integrated.

Q35. The Scoping Ruling asks parties to propose which existing DR programs should be categorized as load modifying. What is your proposal?

A35. All response to dynamic pricing is essentially load modifying and should be treated as such. In addition, any existing or future IOU DR programs that do not need to be dispatched by the CAISO, or are not cost-effective if integration costs are included, or both, should be categorized as load modifying. These would be load reduction programs and could be in response to price or event signals. They will still reduce load and thus system or local RA procurement needs. They will not provide flexibility or A/S like regulation, which require CAISO control.

---

frequency relays (UFRs) and, if the trip frequency is set at a level approved by the CAISO, it does not need to be integrated into the CAISO's markets. Currently, customers on PG&E's BIP program have a UFR option. Clearly, UFRs involve a customer giving up control of part of its load, which will limit participation. However, if the customer is willing and if the technology is cheap, it could be used by some of the same end uses that can provide contingency reserves.

Q36. The Scoping Ruling asks if the Commission needs to improve forecasting for load modifying resources. What is your response?

A36. Yes, it does. There are actually two issues here. The first is that the Commission should particularly focus on forecasting the impact of dynamic pricing events as well as expanding its use of dynamic pricing. The second is that the CAISO should adjust its load forecasts to take into account the impact of these dynamic pricing events when engaging in Residual Unit Commitment and Real-Time Unit Commitment. Otherwise, the CAISO will over-procure resources.

It is important to note that there are far more studies of the response of load to dynamic pricing events than there are of using DR to provide A/S or flexibility. The results of these studies have been presented in the Residential Rate Design case (R. 12-06-013) and in numerous dynamic pricing dockets. The Commission has a policy of encouraging dynamic prices for various groups of customers, as well as rolling out time-of-use rates for larger and larger groups of customers; accordingly, the impact of these options on customer loads and load shapes should be an important consideration and should be factored into both planning and operational decisions.

VIII. Program Budget Application Process

Q37. Attachment A to the Scoping Ruling asks about longer budget cycles for DR. Do you have any recommendations about the budget cycle?

A37. Given the time it takes to establish a DR program and recruit customers to participate, longer budget cycles would be helpful. In addition, and even more important, DR program stability is very important to customers. If a customer participates in a program, it does so because the terms and conditions and remuneration are acceptable. If the terms and conditions or compensation are subject to frequent change, the customer must constantly re-evaluate its participation. This is the reason why there are annual opt-out windows for reliability-based DR. Furthermore, once the customer leaves the program, it is less likely to return. Thus, I would recommend that longer budget cycles also be combined with more stability in individual DR programs.

IX. Back-up Generation

Q38. The Scoping Memo asks the following questions regarding the use of back-up generators by customers providing DR:

- How should the Utilities collect data on the customer's use of fossil-fuel emergency BUG during the demand response events? Identify the amount of demand response provided by BUG on an on-going basis?
- How can this policy be further implemented for the Utilities' existing and new demand response programs as Supply Resource and Load Modifying Resources? What methods should the Commission use to exclude demand reduction provided through the use of BUG?
- Should the Commission require on-site sub-metering for BUG and/or should the Commission require self-certification with the inclusion of data regarding the intended use of BUG during demand response events? If on-site metering is preferred, how should the costs of the metering be recovered? (Scoping Ruling, Attachment A, at 7-8)

What is your position on these questions?

A38. There is no reason why anyone other than the customers themselves or their air quality regulators should know if they have back-up generators or determine when and how these generators can be used. These customers are all subject to appropriate air quality regulations. It is not the CPUC's jurisdictional responsibility to enforce air quality regulations at either the state or the federal level.

X. Cost Recovery

Q39. The Scoping Ruling asks a number of questions about the recovery of costs of each utility's current DR programs. The questions are:

- Provide a summary of each of the Utilities' current demand response program cost recovery and provide citations for the decisions authorizing this recovery method.
- Should the current cost recovery policy be changed? Please describe your proposed alternate cost recovery methods for the Supply Resource and Load Modifying Resource demand response programs in the future?
- Are there fairness issues that the Commission should consider for Commission regulated utilities and other Load Sharing Entities? Please describe these issues in detail, with specific recommendations for resolving and/or avoiding these issues. (Scoping Ruling, Attachment A, at 8.)

Please provide a response to these questions.

A39. The current method of recovery of DR program costs will no doubt be included in the testimony of each utility. In general, this matter is taken up in Phase Two of general rate case proceedings. The allocation of the costs is usually subject to the terms of a settlement in these proceedings. The actual recovery must be in a charge that applies to the appropriate group of customers, i.e. if some of the costs and some of the RA credit are assigned to DA or CCA customers, those costs must be recovered through a charge that is paid by those customers.

Reliability-based DR programs support the grid that serves all customers on a system or local basis if needed, reducing the risk of Stage 1 or 2 emergencies or rolling blackouts. All customers of appropriate size, regardless of their LSE, may participate in these programs. In exchange, RA credit is assigned to all LSEs on a load ratio share basis. Thus, recovering the costs of reliability-based DR programs from all customers makes sense and should be continued.

Non-reliability-based DR programs have historically been operated by utilities in response to program triggers, which include reliability-based triggers, both system and local, as well as proxies for price-based triggers (i.e. heat rates and temperatures). In the near future it will be possible to offer these into CAISO markets, if it is cost-effective to do so, as supply resources. If this is done, these programs will expand the offers in those markets and have the potential to reduce market clearing prices paid to serve all customers. The costs of non-reliability-based DR programs are recovered differently for different utilities. For example, PG&E recovers the costs of its aggregator-managed programs only from bundled customers. However, if these programs are offered into CAISO markets and reduce market-clearing prices for all load, why should only bundled customers pay for them?

In short, in order to address whether there should be a change in the recovery of these costs, it is appropriate to consider the fairness issue in the third bullet.

This is a subject area where fairness has for many years been in the eyes of the beholder. I have just indicated that both types of DR programs, reliability-based and non-reliability-based, have a positive impact on reliability and the latter may have a positive impact by reducing market prices. Furthermore, as current utility DR programs are structured, customers of all LSEs may participate in all utility DR programs except for pricing options. I understand that non-utility LSEs may wish to develop their own DR programs for one or both purposes and are concerned that their customers will pay for both utility and their DR programs. On the other hand, non-utility LSEs have no obligation to develop their own DR programs in lieu of utility programs.

I can see a few ways to address this concern. The first is for each LSE to have the same DR obligation which can be met through either utility DR programs or their own. However, this would require that a DR obligation be imposed on non-IOU LSEs and the Commission does not have the authority to do this. Furthermore, it would require the establishment of a DR procurement target, similar to the Renewable Portfolio Standard, and I have argued that there is no viable basis for such a goal at this time. The second is for all LSEs to offer DR into a common auction or pool with the best programs being chosen and the costs shared among all LSEs. The problem is that, once again, participation would have to be voluntary for all non-utility LSEs. It is not fair for IOU bundled customers to pay for DR that is required of them and to have DA and CCA customers have no obligation to share in the costs or have their own programs so that there is a level playing field.

I recommend that the Commission convene a set of workshops with participation from representatives of various LSEs to see if they can come up with a mutually agreeable solution. Otherwise, without legislation to require similar obligations on the part of all LSEs, I cannot see a way to recover the costs of DR programs that will not leave one or more LSEs claiming it is unfair.

Q40. Does this complete your testimony?

A40. Yes, it does.

APPENDIX A

QUALIFICATIONS OF BARBARA R. BARKOVICH

Barbara R. Barkovich has a BA in Physics from the University of California at San Diego, an MS in Urban and Policy Sciences from the State University of New York at Stony Brook, and a Ph.D. in Energy and Resources from the University of California at Berkeley.

Dr. Barkovich worked on energy and environment issues for the National Science Foundation in 1974-75. Dr. Barkovich worked for the CPUC in 1975-1983, ending up as Director of Policy and Planning. In her time at the Commission, she dealt with broad energy policy issues, as well as revenue allocation and rate design, marginal cost development, electric resource issues, including transmission and generation, and representation of the Commission at the Legislature, the Governor's Office, and Congress.

From there Dr. Barkovich spent almost two years running a short-term financing program at a major bank holding company. Since then (1985), she has been a consultant and expert witness on energy (especially electricity) and regulatory matters, including marginal cost, cost allocation and rate design, electric industry restructuring, electric resource analysis, due diligence for energy projects, and negotiations on behalf of electric consumers with utilities and energy service providers on pricing and service matters.

Dr. Barkovich has also served on the California Independent System Operator Governing Board and the Energy Engineering Board of the National Research Council.