BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots, and Budgets for 2012-2014	Application 11-03-001 (Filed: March 1, 2011)
And Related Matters	Application 11-03-002 Application 11-03-003

OPENING BRIEF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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The California Independent System Operator Corporation ("ISO") submits its Opening Brief pertaining to the Demand Response Applications and Budgets of Applicants Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E") and Southern California Edison Company ("SCE") for the 2012-2014 program cycle. The ISO has formatted and outlined its brief to follow the briefing outline set forth in ALJ Hymes' August 1, 2011.[1]

1. INTRODUCTION

The record shows that the IOU demand response programs for the 2012-2014 program cycle still need adjustment and corresponding efforts to transition event-based demand response resources to fulfill their role as supply side substitutes which will viably support California's energy transformation to a 33% renewable portfolio standard ("RPS"). Part of the effort to ready demand response to meet future needs means adjusting the current program configurations now so that traditionally styled demand response programs do no crowd out newer configured and even pilot programs for demand response that is part of the effort needed for demand response to fulfill the role the energy agencies, including this Commission, have set in the Energy Action Plan Loading Order as an energy and capacity resource to be favored over conventional generation.

2. OVERARCHING ISSUES

2.1. EVALUATING COST EFFECTIVENESS

Every retail demand response program should be cost-effective on its own merits

Each proposed demand response program included within an IOU's Application must be required to stand on its own and not rely upon bundling within the overall program portfolio to bring the average up to par and over 1.0. The Commission should require individual demand response programs that fail the Commission-approved cost-

[1] Administrative Law Judge's Ruling Providing Guidance for Briefs, August 1, 2011 and Attachment A.

effectiveness tests by falling below the 1.0 rating to be adjusted so that the individual program itself passes the rating and can therefore be considered cost-effective.

ALJ Hymes' cross-examination of SDG&E witness on the second day of evidentiary hearings indicates that the IOUs have taken the position that programs that fail the cost-effective test on their own merits can simply be packaged with other programs and survive as long as the average cost effectiveness of the overall program package is over 1.0:

ALJ Hymes' cross examination of SDG&E witness Kevin McKinley:

Q ... Why is SDG&E's portfolio cost effectiveness so low but most of the individual programs are cost effective?

WITNESS MC KINLEY:

A I think if you look at the testimony, most of the programs on the TRC do fall below one.

Q So do I have my question backwards?

A Possibly. I can tell you that there are just a couple programs that pull the whole portfolio one way or the other.

That is generally why --

Q Let me make sure I understand. SDG&E's overall portfolio is cost effective?

A Yes.

Q It's over one?

A Yes, when you include the PTR program.

Q But there are indeed programs that are not cost effective?

A That's correct.

Q Can you give me some understanding how that happens.

A Sure. We have been directed to use methodology from the CPUC which is to use the E3 template which has most of the assumptions already built in. And we also have protocols we have to follow in order to do the cost effectiveness for both cost effectiveness and for the load research for the loads that we use.

> So when we use those, it looks like a number of the programs are fairly close to one, but we have one program that is very high, has a very high TRC, which is the PTR program, and when you throw that in with the ones that are of lower value, like PLS and small commercial technical deployment program, then the average still pulls up enough so that the overall portfolio is over one.[2]

The ISO fails to see the logic for allowing portfolio averaging when, for example, as SDG&E's testimony reveals, it is only because the PTR program creates enough "cost-effectiveness headroom" to bring several subpar programs rated below 1.0 to a collective average of above 1.0 on a portfolio basis.

The Commission should require the IOUs adjust program attributes, such as customer incentives and program availability, to ensure the result that each program is individually cost-effective. Individual programs that fall below 1.0 are not cost-effective (i.e. they are subpar) and should not be permitted to be bundled to meet the Commission's cost-effectiveness standard. The Commission should require that demand response programs, like other supply resources and procurement contracts, must be reasonable, competitive and cost-effective on their own merits.

Avoided T&D costs are correctly assigned a zero percentage D Factor in the cost effectiveness calculations

The ISO does not see how an IOU can make a non-zero avoided Transmission & Distribution ("T&D") showing if the demand response program is not locationally dispatchable, when and where it is needed, so that it can effectively avoid or defer a T&D concern. The definition of the *D Factor* is that it "adjusts the estimated benefits of a DR program to avoid or defer upgrades to the transmission and distribution system."[3] In order to assign a non-zero D Factor to a program, the IOU must clearly demonstrate how (i) the demand response program avoids T&D investment and asset deferral and (ii) the

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[2] Vol 2 Reporters' Transcript p. 270, line 19 to p 271, line 28 (ALJ Hymes' cross-examination of SDG&E witness Kevin McKinley) (italics added for emphasis).

[3] Joint Assigned Commissioner and Administrative Law Judge's Ruling and Scoping Memo, May 13, 2011, Attachment 1, at p.. A2.

IOU has incorporated the program into the IOU's T&D planning process and/or into any IOU T&D remedial action scheme.

2.2. DUAL PARTICIPATION RULES

[The ISO has no opening position to present at this time on this outline subject.]

2.3. BASELINE METHODOLOGY

No changes should be made to the existing baseline methodologies until further analysis is conducted

The Energy Division served a Data Request on each IOU Applicant which was designed to gather information to determine whether a baseline adjustment factor might be applied to demand response baselines. The Energy Division requested that each IOU calculate baseline settlement results for the months of July, August, and September 2010, using both individual and aggregated baselines and apply a range of various adjustment factors -- 30%, 35%, 40%, 50%, and "no cap" -- for two demand response programs, CBP-DA and CBP-DO. The Energy Division asked the IOUs to compare the derived 2010 baseline settlement results with the 2010 measurement and evaluation results.

Each IOU complied with the request and provided results.[4] The ISO reviewed the IOU's Data Responses and filed comments on the responses (along with other parties) on August 11, 2011. The ISO's response is worth repeating here.[5]

While the ISO recommends that it is indeed appropriate to add an adjustment factor to the IOU demand response baseline methodology, the Data Response results clearly indicate that further analysis is needed before selecting a particular adjustment factor. This is because the Data Responses revealed that no particular adjustment factor

[4] Note that spreadsheet Baseline Analysis information provided to Energy Division by SCE and SDG&E are posted on the Commission website at: http://docs.cpuc.ca.gov/efile/CM/141768.pdf http://www.cpuc.ca.gov/PUC/energy/Demand+Response/a1103001_appendices.htm .

[5] The ISO's comments to the IOU data responses is posted to the Commission website at: http://docs.cpuc.ca.gov/efile/CM/141768.pdf. ALJ Hymes incorporated the IOU data request responses into the evidentiary ruling by ruling dated August 5, 2011. The ISO reads this ruling to incorporate the parties' comments to the data request responses into the evidentiary record as well.

was a "best match" for more than one IOU -- what was a "best match" for one IOU was not a best match for any other. Therefore, the ISO concluded, along with SCE, that "…the analysis as requested … [was] of severely limited usefulness, and … [fell] well short of sufficient information to make an informed decision on setting the baseline adjustment."[6]

As the ISO stated in its comments on the Data Responses, in order to conduct a proper evaluation, a deeper analysis is needed across a variety of program and product types, compared across utilities and other ISOs/RTOs. For instance, both the California ISO and New York ISO apply a 20% symmetrical adjustment factor in their baseline calculations, and the ISO's baseline methodology for its proxy demand resource product was approved by FERC and deemed just and reasonable. To apply an adjustment factor as the ISO recommends, then the Energy Division will need to determine whether to apply the adjustment factor symmetrically or asymmetrically.

The impact of adjustment factors in baseline calculations is an important topic that merits the Commission's further analysis and is an issue worth settling conclusively through the application of detailed facts and analysis. The ISO recommends that the Commission order the utilities to conduct a professional and comprehensive study of adjustment factors across a range of retail and wholesale demand response programs in the range of 20% and 50%, including a no-cap case to be completed within the first quarter of 2012. This should give sufficient time for implementation by 2013, if changes are warranted. Thus, the ISO recommends that the Commission maintains the existing baseline methodology through 2012 and decides on changes once more substantiated data and analysis are available.

[6] See explanation provided in SCE's linked spreadsheet, "Analysis Notes" tab, found at http://www.cpuc.ca.gov/PUC/energy/Demand+Response/a1103001_appendices.htm

3. EMERGENCY PROGRAMS

3.1. COMPLIANCE

[The ISO has no opening position to present at this time on this outline subject.]

3.2. REASONABLENESS

SCE and SDG&E should be required to institute PG&E's proposed BIP eligibility screening process

PG&E pointed out in its prepared testimony that "some [new] applicants do not have a natural fit with the BIP [Base Interruptible Program] program."[7] Given the similarity in the BIP program across the IOU service territories, the potential for applicant "misfits' likely applies to each IOU BIP program. A pre-enrollment qualification for new entrants and non-complying participants, as PG&E has proposed, is a reasonable program element and should minimize customer complaints on the back-end as customer's would not be enrolled in a program that is a poor fit and results in poor performance, penalties and the potential for a bad experience.

3.3. MEETING FUTURE NEEDS

[The ISO has no opening position to present at this time on this outline subject.]

4. PRICE RESPONSIVE PROGRAMS

4.1. COMPLIANCE

[The ISO has no opening position to present at this time on this outline subject.]

4.2. REASONABLENESS

[The ISO has no opening position to present at this time on this outline subject.]

4.3. MEETING FUTURE NEEDS

Demand response programs must be made available beyond weekday and peak-periods to address future reliability needs under a 33% RPS

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[7] Exhibit PGE-1, PG&E's Opening Testimony, Chapter 2 at p. 2-21, line 28 to p, 2-22, line 10 (Testimony of Erik V. Olsen and Boaz E. Ur).

In its Direct Testimony, the ISO specifically encouraged SCE to incorporate weekends as eligible days for its Capacity Bidding and Demand Bidding Programs as the ISO has experienced peak loads and emergencies on weekends and during non-peak hours.[8] Additionally, increasing numbers of intermittent renewable resources means greater supply-side variability and, therefore, less supply-side controllability to balance load every hour of the day. The expectation by state and federal policy makers and opinion shapers is that demand response will be a complimentary resource to help attenuate supply-side variability by acting as a shock absorber on the demand-side and helping California meet to its legislatively-mandated 33% RPS.

This 2012-2014 program cycle presents a timely opportunity to familiarize and educate customers about the need for demand response in all hours of the day as we move toward a 33% RPS. The effort is necessary for California to prepare for the operational challenges of greater supply side variability and intermittency that are just a few years away. Expanding program availability will enable customers that can provide demand response during non-peak hours and on weekends to offer demand response. Moreover program expansion will provide the IOUs an opportunity to learn more about customer demand response patterns that can be expected during non-peak and weekend hours and the customer types that can be expected to participate. The ISO is cognizant of the fact that not all customers will be able to provide this service, but why limit opportunities for those that can? The Commission should insist on incremental, forward thinking program changes that help prepare the way for California's energy future.

An ambient temperature should never require the IOU or customer to trigger a demand response program; dispatch should be based on economics and actual need

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[8] The ISO's Direct Testimony is Exhibit ISO-1. The pertinent testimony is at Section V (D), p. 18, lines 16-27 (testimony of John Goodin).
The ISO publishes on its website a record of all the alerts, warnings and emergencies the ISO control grid has experienced since ISO startup. A record of these events by year, month and hour can be found using this link: http://www.caiso.com/informed/Pages/Notifications/NoticeLog.aspx

The ISO clearly understands that high ambient temperatures drive increased demand, but a high ambient temperature does not always correlate with events of energy shortage or very high wholesale electricity prices, the events in which demand response dispatch has historically been most cost and operationally effective.

As SCE has conveniently pointed out in its rebuttal testimony to the ISO's direct testimony, on the fifteen highest peak load days in SCE's service territory in 2009 "the MRTU day-ahead market price is more closely correlated to the on-peak energy price of the OAT, thus offering little or no price volatility to encourage additional load reduction during times of high system load."[9] SCE also noted that "[o]ver the 2009 summer period, SCE's RTP-2 rate structure provided an on-peak price signal 87 percent greater than the MRTU day-ahead price and a price signal four to five times greater than the OAT on-peak and MRTU day-ahead prices during the 15 highest system peak days, respectively [FN omitted]." [10]

Appropriate questions to ask are these:

- Was an arbitrarily high, temperature-based price that was 87% higher than the day-ahead price (15.7 cents/kWh versus 10 cents/kWh, respectively) an appropriate price signal to send to RTP-2 customers on these particular days?
- Was the load curtailment and customer disruption appropriate, given that, as SCE points out, the wholesale prices were reasonable and volatility was low?
- Was there a cheaper, more economic resource that SCE could have dispatched, particularly since a 15.7 cents/kWh rate translates into the dispatch of an equivalent high heat rate resource?

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[9] Exhibit SCE-07, Amended Rebuttal Testimony of SCE, at p. 26, lines 21-24 (testimony of Ms Kevin Wood).
[10] Id., at p 27, lines 2-5 (testimony of Ms Kevin Wood).

The RPT-2 tariff requires customers to curtail load or pay a "hard- coded" tariff price that may be much higher than the supply price corresponding to actual system conditions. The RTP-2 rate of 15.7 cents/kWh represents the equivalent of an extremely high and inefficient heat rate resource based on natural gas prices in 2009, and, therefore, was conveying a high price signal appropriate relative to actual system conditions? This is precisely why future dynamic ratemaking must be based on wholesale market prices which reflect grid conditions, not some pre-set tariff value. A pre-set tariff value has the potential to send an inaccurate price signal since it is only a purported proxy for system conditions. As that facts that SCE point out convey, a pre-set, temperature-based tariff price or program trigger is arbitrary, inefficient and outmoded and does not necessarily correlate to system conditions and need.

An additional fact that SCE does not mention in its Amended Rebuttal Testimony regarding these fifteen highest peak loads in 2009 is that the ISO had no significant operational challenges meeting load on these fifteen days.[11] No alerts, warnings or emergencies were declared by the ISO. Only on one of the fifteen days, August 28, 2009, did the ISO issue a "restricted maintenance operations," notification, the minimum level notice the ISO publishes concerning system conditions. Again, these peak load days in SCE's service territory where likely very hot, but the fact that the ISO did not declare a shortage condition indicates that the ISO had sufficient resources scheduled and committed to manage the peak demand.

SCE makes an additional point in its Amended Rebuttal Testimony that highlights a misunderstanding about wholesale and retail markets and the customer role. SCE states that "what CAISO fails to recognize is that not all DR customers are as sophisticated as

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[11] See Vol. 4 Reporters' Transcript at p. 510, lines 22 to p 511, lines 511 where PG&E's counsel Mary Gandesbery cross-examined ISO's witness John Goodin on SCE's 15 highest load days in 2009, information from SCE's Amended Rebuttal Testimony on temperature triggers. [Mr. Goodin: "…in SCE's testimony, rebuttal testimony, they give the 15 highest load days in 2009. Not one of those days shows up in our alerts, warnings or emergencies, on one. And yet those were probably hot, very stressed days. But no emergencies happened on that day or on those 15 days."]

those entities providing supply-side resources that consistently monitor market prices. For many of SCE's customers, providing a temperature trigger provides an appropriate and simple signal that functions as an appropriate proxy to market conditions."[12] The ISO understands that a majority of customers will have no interest in monitoring wholesale market prices. Monitoring wholesale prices is important for the entity responsible for resource procurement and scheduling. SCE, as the scheduling coordinator and wholesale procurement agent, is the entity responsible for ensuring least-cost procurement for its customers and determining whether to schedule and bid particular resources, including event-based demand response resources. Analyzing and forecasting wholesale market prices likely an important factor in SCE's procurement decisions and a component for assessing which supply options, including demand response, it will exercise on a day-to-day basis. Demand response programs are another "economic" resource (though often a use-limited one) that the utility can exercise when making decisions to ensure least-cost procurement for its customers. The decision to schedule or bid a particular resource, call on a demand response program, or issue a critical peak pricing notice is a *utility* decision, not the customer's, and it should be based on economics, not on what the ambient temperature is in downtown Los Angeles, even if temperature is driving higher demand.

5. INDIVIUDAL UTILITY PROGRAMS

5.1. COMPLIANCE

At minimum, PG&E's Peak Day Pricing program (PDP) and other Critical Peak Pricing tariffs must not qualify as local resource adequacy capacity in resource adequacy compliance year 2013 if the programs or tariffs cannot be dispatched locationally

Since July 22 (the date the ISO's testimony went into the record stating that the ISO is opposed to the notion of qualifying as resource adequacy capacity resources that

[12] Exhibit SCE-07, Amended Rebuttal Testimony of SCE, at p 37, lines 11-14.

are not available to the ISO "when and where needed") the Commission has issued a proposed decision in its resource adequacy proceeding supporting the point that demand response RA should be dispatched locationally. In the Commission's Resource Adequacy Rulemaking (R.09-10-032),[13] the Commission has released an August 9, 2011 proposed decision of ALJ Gamson, *Decision Further Refining the Resource Adequacy Program Regarding Demand Response Resources,* with respect to the 2012 Resource Adequacy Program[14]. In its treatment of demand response resources, the proposed decision proposes a requirement of local dispatch capability in order for demand response resources to qualify as local resource adequacy resources. The proposed decision states:

> We agree in principle with the CAISO that the fundamental reason for a locational dispatchability requirement for all RA resources is to meet local capacity needs.[15]

The proposed decision makes clear that "a demand response resource may receive local RA credit only if it is capable of being dispatched by the CAISO in a defined RA local area."[16]

The resource adequacy proposed decision is in accord with the ISO's testimony in this proceeding recommending that the Commission count as local resource adequacy only those demand response resources that are capable of dispatch for purposes of ISO-grid operations in the local area in which the need occurs. Allowing demand response programs to count for local resource adequacy when they lack the "`dispatchablity' where needed" attribute of all other resource adequacy resources violates the central tenet of the Commission's Resource Adequacy Program.

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[13] Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations
[14] The proposed decision is posted to the Commission's proceeding web page at http://docs.cpuc.ca.gov/efile/PD/141001.pdf, ("proposed decision")
[15] Proposed Decision at Section 3.1.1
[16] Proposed Decision at Section 1 (Summary), p. 2, Section 3.1 (Demand Respond Resource Dispatch by Local Area), p. 5

Every resource can be called a "point" resource because it injects power into the grid at a specific location, be it at an intertie point, generator node, or within a sub-lap, as is the case with the ISO's demand response products. The ISO operates a full network model that considers the impact of energy injections and "load take outs" (as the ISO calls it) at thousands of points on the ISO controlled grid. This allows the ISO to balance loads and resources and ensure a feasible dispatch. As the ISO's witness, John Goodin stated in cross-examination, enabling retail demand response programs like PG&E's Peak Day Pricing program to "inject power" *wherever* the program happens to be located on the grid, when the ISO needs energy *at a particular* grid location, can provide the opposite of grid support, exacerbating congestion management for the ISO and increasing costs for consumers.[17]

To reiterate Mr. Goodin's example from his testimony, assume, for example, that PG&E owns certain combustion turbines around its service territory, including in Fresno, the Easy Bay, San Francisco and Humboldt and the ISO needs incremental energy to resolve a transmission constraint in Fresno. To maintain system balance and address the local constraint, the ISO will try to dispatch available generation in Fresno and back off other resources outside Fresno as the most effective dispatch. The idea is to keep the system balanced and keep system frequency in-check so that there is minimal need for incremental or decremental energy. If the ISO was required to dispatch the turbines analogous to PG&E's Peak Day Pricing program, where dispatch must necessarily occur in more than one area, then, even though the ISO only needed a specified amount of supply in Fresno, the ISO would have to dispatch all of PG&E's turbines in the various areas across PG&E's service territory. This might be effective in addressing the local constraint in Fresno, but the ISO would have to rebalance the system in the other areas (i.e. the Bay Area, San Francisco and Humboldt) by backing off other resources, since

[17] Vol 4 Reporter's Transcript, at pp 504, line 5 - p 506. Line 28 (cross-examination of Mr. Goodin by Ms. Gandesbery).

more energy is being injected into the grid in those other areas than is needed. This can have a financial consequence, given that resources are adjusted by the ISO according to market bids.[18]

In addition to these reliability concerns that Mr. Goodin's testimony illustrated, there is also a cost associated with disrupting all customers on a demand response program, when only a minority of customers on that program are actually needed to respond. Load curtailment can be disruptive and result in customer and societal costs, such as lost productivity, costs that may exceed a utility's direct program costs and the long-term cost to get demand response to conform and operate more equivalent to a point resource, available when and where needed.

Accordingly, the Commission should ensure that there is clear articulation in the IOU applications as to how each IOU plans to provide local dispatch for demand response that qualifies as local resource adequacy capacity.

5.2. REASONABLENESS

[The ISO has no opening position to present at this time on this outline subject.].

5.3. MEETING FUTURE NEEDS

[The ISO has no opening position to present at this time on this outline subject.]

6. ENABLING TECHNOLOGIES (INCLUDING TA, TI, AUTO DR AND PLS)

6.1. COMPLIANCE

[The ISO has no opening position to present at this time on this outline subject.]

6.2. REASONABLENESS

[The ISO has no opening position to present at this time on this outline subject.]

6.3. MEETING FUTURE NEEDS

[The ISO has no opening position to present at this time on this outline subject.]

[18] Id.

7. MARKETING, OUTREACH AND EDUCATION

7.1. COMPLIANCE

[The ISO has no opening position to present at this time on this outline subject.]

7.2. REASONABLENESS

[The ISO has no opening position to present at this time on this outline subject.]

7.3. MEETING FUTURE NEEDS

[The ISO has no opening position to present at this time on this outline subject.]

8. MEASUREMENT AND VERIFICATION

8.1. COMPLIANCE

[The ISO has no opening position to present at this time on this outline subject.]

8.2. REASONABLENESS

[The ISO has no opening position to present at this time on this outline subject.]

8.3. MEETING FUTURE NEEDS

[The ISO has no opening position to present at this time on this outline subject.]

9. PILOTS

9.1. COMPLIANCE

[The ISO has no opening position to present at this time on this outline subject.]

9.2. REASONABLENESS

[The ISO has no opening position to present at this time on this outline subject.]

9.3. MEETING FUTURE NEEDS

[The ISO has no opening position to present at this time on this outline subject.]

10. PG&E'S CURRENT AGRREGATOR MANAGED PORTFOLIO (AMP)

[The ISO has no opening position to present at this time on this outline subject.]

11. FORWARD LOOKING ISSUES

11.1. INTEGRATION WITH STATE OF CALIFORNIA ENERGY POLICIES

The Energy Action Plan calls for demand response to be a supply-comparable resource

The Loading Order set out in the Energy Action Plan (EAP) is turned on its head if it is cited as a basis for maintaining the status quo for demand response, and turning out, in this budget cycle, programs with only incremental change from retail demand response programs of the past. RPS demands much more from demand response. All dispatchable, event-based demand response should be integrated into the ISO market. The EAP Loading Order supports this path. The Loading Order, as specified in EAP II, describes a policy priority for satisfying increasing energy needs in California with demand response as a principal resource, specifically:

> EAP II continues the strong support for the loading order – endorsed by Governor Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. *The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs*. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent [that] efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy *and capacity needs*, we support clean and efficient fossil-fired generation.[19]

The ISO encourages the Commission to look closely at the wording above. Energy and capacity needs are not fulfilled by old-fashioned demand response which merely substitutes for load shedding. The Loading Order does not advocate that California meet the critical energy needs of its economy through load shedding. Load shedding does not provide the "energy and capacity" that the EAP envisions from demand response. Supply side substitutes do. It is the ISO's opinion that the role for demand response envisioned in the EAP—that of *parity* with traditional generation resources as a means of meeting the state's "growing energy needs" —cannot be achieved through promotion of the status quo and with limited integration of event-based demand response into the ISO market. The state mandate to satisfy a 33% renewable

[19] Energy Action Plan II, September 21, 2005, pg. 2 (emphasis added). This document is posted to the CEC's Web Site at http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

portfolio standard by 2020 makes the need for supply-substitute demand response all the more important. We should not wait to 2015 to start preparing demand response for the role it must play in 2020. If we measure the pace of demand response progress to supply side substitute from the time the EAP was first issued until now, waiting to 2015 won't give us enough time.

The EAP does not promote an irrational pursuit of "any type" of "cost-effective" demand response program. The Commission has a responsibility to ensure that investment in demand response in this program cycle is established in a right and rational manner, so that ratepayers benefit from the right and appropriate types of demand response resources that can actually defer generation investment and help California achieve a 33% RPS. This means demand response that is dispatchable and is configured to provide fast response, like non-contingent non-spinning reserve, to act as a "shock absorber" on the grid as supply-side output grows more variable and immediate dispatch less certain over the next number of years. Successful fulfillment of the EAP policy requires having a "right type and right mix" of resources that can both reliably and cost-effectively meet the state's future energy needs and energy policy goals.

If the EAP is to succeed in substituting alternative and or traditional generation resources with demand response, then demand response must be a suitable resource replacement capable of maintaining system reliability and integrity under normal (non-emergency), but stressed, system conditions. The 2008 EAP update[20] clearly states that a next step is to "[m]odify retail [DR] programs so that they can more fully participate in the California ISO's new wholesale market structure."[21]

The EAP emphasizes that "…the California Independent System Operator (ISO) can be instrumental in incorporating demand response policies and appropriate

[20] This is the 2008 Energy Action Plan Update, posted to the CEC website at http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF.
[21] 2008 Update Energy Action Plan, February 2008, at p. 11

operational rules at the wholesale level thereby *allowing aggregated demand-side resources to be scheduled on the system along-side conventional generation*."[22] Thus, in the ISO's opinion, the Commission is well advised to closely scrutinize the proposed event-based demand response programs and the ability of these "supply resources' to transition into the ISO market over this application cycle as part of its overall policy to promote demand response in accordance with the Loading Order and in order to position demand response as a resource that will assist California in meeting the 33% RPS. In this same spirit, the ISO also encourages the Commission to resume Phase 4 of its demand response proceeding R.07-01-041 and resolve the open policy issues pursued in that phase of the rulemaking proceeding.

In its Opening Testimony, PG&E suggests that the link between the Loading Order objective to make demand response a supply resource and the certainty and confidence to which demand response programs can actually be relied upon in a utility's resource procurement and planning process is many years away: In its section entitled "The Long-Term Procurement Plan and DR," PG&E offers an apologia:

> DR is a large component of the electric portfolio and cannot be represented by a single point forecast in the long-term plan process given the uncertainty with program design changes, enrollments, customer response to changing programs and the potential changes in hours of operation and types of need to be satisfied by DR programs in the future.[23]

PG&E then goes on to note that pilot efforts will be undertaken. The ISO appreciates and endorses pilot activities, but the emphasis on moving to the future is too incremental and slow. .

SDG&E's responses to cross-examination questions by ALJ Hymes are also telling. The question and answer relating to how demand response will transition to meet RPS goals indicates that this is not at the forefront of IOU planning, and that there is no

[22] *Id*. at p. 10 (emphasis added).
[23] Exhibit PGE-1, Opening Testimony of PG&E, Chapter 7, page 7-19 lines 6-10 (testimony of Kenneth Abreu).

ultimate vision of the goal: The default approach seems to be that "the ISO will take care of it," apparently with non-IOU program demand response:

ALJ Hymes' cross-examination of SDG&E witness panel

Q And do you think the critical peak pricing will help with problems such as over-generation or the increased need for ramping during shoulder hours?

A *[Witness Mark Gaines] Well, I think those are more ancillary service and energy demand response programs, and I think the CAISO wholesale market is probably better suited for that.*[24]

Q And does SDG&E have a long-term vision?
You know, we talk about demand response, and we've talked a lot about energy efficiency here. And with the strategic plan, there is a discussion, although it hasn't played out as much, but a discussion about demand response in the Commission's strategic plan.

Q *Does SDG&E have a vision or a long-term plan regarding DR and how to, how to fulfill these policy goals such as 33 percent renewables?*

A I'm not sure I fully understand the question. Is it how we are going to fully utilize demand response to meet the reliable need or how we're integrating all of our programs?

Q I would say both.

A *Well, I think it mostly comes to the Commission's direction on integrated demand response programs.* We have that pro- -- that program is included in the demand response filing as well as in the energy efficiency filing. That effort is intended to make sure all of the activities are integrated, maximizing the use of energy efficiency demand response and renewables to achieve the state's goals in the loading order.

Q Okay.[25]

[24] Vol. 2 Reporter's Transcript at p. 286, lines 16-25.
[25] *Id*. at p 268, line 16 – p 269. 26.

For context, the ISO notes that another witness added a comment to discuss pilot and other activities that he indicated have some relationship to demand response.

WITNESS KATSUFRAKIS: A Just to add to that.
Q Sure.
A We are looking at -- we have a pilot in our territory where we're looking at control strategies for an island, electric island, where we're, it is an integrated approach. There's an energy efficiency piece. We're asking for a small amount for DR. But there's

If future energy needs cannot be supplied with demand response then it must be supplied with generation. The ISO agrees that the Loading Order explicitly recognizes the substitutability of demand response for supply. Thus, demand response must be available and able to offset the nature and character of generation. If it cannot, then it is not substitutable and the Loading Order is pointless.

11.2. INTEGRATION WITH CAISO MARKETS

The Commission should use this application cycle to fully integrate event-based demand response into the ISO market

The ISO's testimony in this proceeding (both the Direct Testimony and cross-examination of ISO's witness John Goodin on July 22) provides the foundational basis for the determination echoed in the Commission's recent August 9, 2011 proposed decision Resource Adequacy Program for 2012 Demand Response Resources in proceeding R.09-10-032 as to why many of PG&E's testimonial arguments about the use, qualification and nature of demand response should be rejected.

In the ISO's testimony, the ISO clearly illustrated for the Commission why locationally dispatched demand response is many times more effective than system-wide demand response. Indeed, system-wide dispatch of demand response resources has the potential to cause more grid problems than it solves by causing imbalance in other locations where it provides additional energy supply. The ISO's testimony in this proceeding complements and reinforces the determination —rendered in contemporaneously issued proposed decision in the RA rulemaking-- that demand response that qualifies as resource adequacy capacity must be a supply-comparable resource. The proposed decision emphasized this point by:

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also supply-side piece where they're looking at control strategies for dealing with clouds, PV systems, and the short-term adjustments that are needed to be made.

Q Thank you

Id. at p 269, line 27 – p 270, line 13.

- Creating a specific Maximum Cumulative Capacity (MCC) bucket for demand response;[26] and
- Requiring local dispatchability for demand response that qualifies as local resource adequacy capacity.

As for the local dispatchability requirement, the ISO stated in its direct testimony that "[t]he ISO has long held the position that only resources that are dispatchable "when and where needed" should count as resource adequacy capacity. This is also a central tenet of the CPUC resource adequacy program."[27]

The proposed decision accords with evidence that the ISO has provided in this proceeding:

> The alternative – forcing the CAISO to manage demand response resources that do not meet a locational dispatchability requirement -- could increase energy costs for consumers by requiring the CAISO both to purchase capacity which may not fit its needs or to purchase additional capacity to cover uncertainties about dispatch.[28]

The ISO recommendation that these changes in resource adequacy counting should not wait for another program cycle and should be addressed in this proceeding is also in accord with the proposed decision.[29]

11.3. DEMAND RESPONSE MARKET COMPETITION

The Commission should be preparing for a fully competitive demand response market by 2015.

As stated in the ISO opening testimony, the Commission should consider the competitive procurement of demand response as an alternative to the IOU's investing in

[26] The proposed decision states in this regard that:

> We adopt the CAISO proposal to create a new MCC bucket for demand response resources for 2013. As with locational dispatchability, we will make this change to current RA policy so that demand response can be treated comparably with supply side resources. The new MCC bucket will help with integration of retail demand response programs with the wholesale market and should significantly increase use of the demand response resources (RA proposed decision at p. 12.)

[27] Exhibit ISO-1 (Direct Testimony of witness John Goodin) at p. 14.
[28] Proposed Decision at p. 7
[29] See Proposed Decision at p. 9.

and building the next generation of supply comparable, dispatchable demand response resources. As the testimony of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets states "[t]he Commission is at a crossroads. While repeatedly stating strong support for competitive markets, it has not addressed how rate regulated utility DR programs and their cost recovery mechanisms operate to the distinct disadvantage of market-based competitors, impeding the formation and development of competitive markets, and stifling innovation for DR products and services."[30]

The ISO perspective is that over these next three years, the Commission should set a course for developing a competitive demand response marketplace by expeditiously settling open regulatory issues such as retail demand response compensation concerns, retail rules for direct participation and resource adequacy treatment for third-party delivered demand response. The Commission should increase the amount of demand response that is delivered directly through third-parties and through competitive solicitation. Under this paradigm, the Commission can still satisfy its directive that IOUs align demand response with the ISO market and EAP Loading Order by directing the IOUs to use competitive procurement to solicit demand response that satisfies long-term procurement needs, resource adequacy requirements, and which can be integrated into the ISO market.

Based on submitted testimony, it appears that PG&E and SCE want to continue to build and maintain a strong demand response portfolio. Regarding enabling the competitive market to build this portfolio instead of the IOU, criticizing the ISO suggestion for the Commission to enable the competitive path, SCE states that "[t]he CAISO has limited experience in DR, while SCE has among the largest and most robust DR portfolios of any utility in the world, and many years of experience managing its DR

[30] Exhibit DAC-1 Direct Testimony of Mark E. Fulmer on Behalf of the Direct Access Customer Coalition and the Alliance for Retail Energy Markets Concerning Competitive Issues in the 2012-2014 Demand Response Program Proposals, A.11-03-001 et al, at pp. 7 - 8.

portfolio. The CAISO's policy recommendation that certain IOU programs may be better provided by aggregators is not only wholly speculative, but, at best, premature."[31] SCE does have years of experience operating retail demand response programs. SCE has minimal experience operating wholesale demand response resources. It is this type of dispatchable demand response resource, along with dynamic pricing, that will be needed to plan and operate the system in the future. The ISO would argue that demand response providers participating in the eastern ISOs and ERCOT have more experience providing wholesale demand response resources than does SCE. California should leverage this experience and the agility and innovation of the competitive market versus investing significant sums of money to develop and build this experience within each IOU.

The testimony of the Demand Response Aggregators rightly point out the California is not ready for direct participation. The Demand Response Aggregators sight several pending regulatory impediments, which the ISO concurs must be resolved.[32] However, progress is being made with ALJ Farrar's recent release of the Commission's Rule 24 proposal on demand response direct participation rules and the creation of a separate demand response MCC bucket in the RA proposed decision issued on August 9, 2011.[33] The ISO believes that the impediments listed by the Demand Response Aggregators will be resolved in this program cycle, which should enable a competitive demand response market by 2015.

The Commission should be preparing for a fully competitive demand response market in 2015. As such, the Commission should keep watch for large expenditures to build the IOUs demand response infrastructure given these funding requests have yet to be made. For instance, PG&E states in its testimony that "PG&E currently intends to request funding for most, if not all, of these other [ISO integration] costs in a subsequent

[31] Exhibit SCE-07, Amended Rebuttal Testimony of Southern California Edison Company, at p. 22 (testimony of Lawrence Oliva).
[32] See Demand Response Aggregators Prepared Direct Testimony, pg. VI-6 – VI-7.
[33] The CPUC's proposed direct participation rules (Rule 24) can be found here: http://docs.cpuc.ca.gov/efile/RULINGS/141712.pdf

application at the conclusion of DR OIR Phase 4 and/or subsequent proceedings, including the 2014 General Rate Case (GRC), for the purposes of implementing the CPUC's requirements to bid DR into the CAISO markets after it is fully informed of the market requirements."[34]

If the Commission desires a competitive demand response market, then it should be mindful of demand response integration expenditures and consider if such expenditures are necessary and cost-effective from a build versus buy demand response products perspective.

11.4. FUTURE AMP CONTRACTS

The ISO supports the competitive solicitation of demand response

The ISO supports the competitive solicitation of demand response resources with the important assumption that these contracted for resources are integrated into the ISO market. The ISO is not taking a position on the need or cost-effectiveness of the AMP program specifically, but strongly supports the concept of competitive solicitation that PG&E is promoting here. This is a paradigm that the Commission should seriously consider as a viable alternative to having each IOU build "in-house" the next generation of demand response resources.

12. FUND SHIFTING RULES

[The ISO has no opening position to present at this time on this outline subject.]

13. APPROVED BUDGETS AND AUTHORIZED EXPENSES

[The ISO has no opening position to present at this time on this outline subject.]

14. REVENUE REQUIREMENT AND COST RECOVERY

[The ISO has no opening position to present at this time on this outline subject.]

[34] PACIFIC GAS AND ELECTRIC COMPANY 2012-2014 DEMAND RESPONSE PROGRAMS AND BUDGETS PREPARED TESTIMONY AND APPENDICES, March 1, 2011, pg 7-6

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Respectfully submitted,

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