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

REPLY BRIEF OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

September 9, 2011

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The California Independent System Operator Corporation ("ISO") submits its Reply 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 brief follows the briefing outline set forth in ALJ Hymes' August 1, 2011 ruling.[1]

2. OVERARCHING ISSUES

2.1 EVALUATING COST EFFECTIVENESS

Cost-effectiveness rules must be applied universally

As the ISO indicated in its Opening Brief, the ISO recommends that every retail demand response program should be cost effective on its own merits. As revealed by ALJ Hymes' cross examination of SDG&E reveals (which the ISO cited to in its Opening Brief), IOUs, including PG&E, have taken the position that, through bundling, one program with a high cost effectiveness can pull the rest of the programs into compliance, even though the other programs would otherwise fail the cost-effectiveness criteria.

As ISO discussed further in Section 11.1 below, PG&E apparently is seeking Commission approval for demand response programs that are not cost-effective on their own merit, yet PG&E implores the Commission to apply strict cost-effectiveness to programs that would integrate into the ISO market. PG&E wants the incremental program costs to match or exceed the incremental ratepayer benefits of transitioning DR programs to bid into ISO's PDR and RDRR product offerings. PG&E proposes strict adherence to "cost-effectiveness" even when it

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

admittedly, through testimony in this record, cannot itself demonstrate how its proposed demand response programs fit into its procurement portfolio (i.e. what resources PG&E did not have to procure because of DR procurement). In addressing the Commission requirement to link its long term procurement plan and demand response, PG&E admits that it simply cannot:

> 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[2]

Consistent cost-effectiveness rules must be applied universally across all demand response types, including the ability to clearly demonstrate how demand response programs fit into the IOUs' procurement plans and avoids or defers investment in generation. Moreover, that fact that PG&E cannot demonstrate the efficacy of this own demand response programs relative to procurement, signals that it is even more inappropriate to adopt its proposal to layer stricter cost-effectiveness standards upon wholesale demand response such that each incremental step meet an incremental benefit before taking further steps toward meeting RPS goals and the loading order.

11. FORWARD LOOKING ISSUES

11.1. INTEGRATION WITH STATE OF CALIFORNIA ENERGY POLICIES

ISO disagrees with PG&E's recommendations H 2, 3 and 4 to decline ISO's proposals.

[2] Exhibit PGE-1, PG&E DirectTestimony, Chapter 7, page 17-9 (Testimony of Kenneth Abreu).

In its Opening Brief, PG&E exhorts the Commission to decline the ISO's recommendations for integration of DR programs into the ISO Market. Specifically, PG&E:

- Disapproves of the ISO's recommendations to hasten the integration of dispatchable DR programs into the ISO market,

- Desires to subject each incremental integration step to an affirmative cost benefit analysis that the costs (to the IOU for in-house development) of each incremental effort no greater than the benefits of bidding into the ISO market; and

- Requests the Commission to continue allowing resource adequacy credit for DR programs that have no connection to the ISO's market.[3]

In its Opening Brief on this subject, SCE notes that key state DR policies are articulated in the Energy Action Plan II, which places demand response and energy efficiency first in the loading order and that "[f]urther the California energy goals focus on the integration of IOU DR programs into the CAISO electricity markets and development of DR programs that enable intermittent energy resources such as renewables."[4] PG&E similarly recites requisites from the EAP and loading order to similarly argue that its programs align with these goals.[5]

We all agree on the goals—the question is whether the program efforts are sufficient to meet these goals. The crux of the matter boils down to the question that ALJ Hymes asked of the ISO's witness John Goodin:

<u>ALJ Hymes' cross examination of CAISO witness John Goodin:</u>

Q Mr. Goodin, have you read the CAISO April 1st response to the Applications, which was filed in this proceeding?

….

[3] PG&E Opening Brief, Summary Recommendations H (1), (2) and (3).
[4] SCE Opening Brief, at p. 71.
[5] PG&E Opening Brief at pp 53-54.

Q In that April 1st response it included a discussion of the CAISO's commitment to ensuring that the grid is ready to support the 33 percent renewable portfolio standard by 2020.

CAISO also stated that demand response must be configured to play a pivotal role in integrating greater amount of variable energy resources so that these resources may help address the operational challenges of intermittent renewable resource output and shaping load to match generation characteristics.

Could you discuss whether the Applications of the utilities address those concerns? Specifically, do they demonstrate the long-term preparations and visions necessary to meet those challenges?

A Overall, I don't believe that they are getting there fast enough for what is about to hit us in around 2015, assuming the 33 percent policy, which the voters have spoken, is going to go forward. That's why I keep emphasizing that this 2012 through '14 is so critical to get these programs reconfigured to be used and useful by the ISO so we can address many of the challenges, operational, reliability challenges of integrating variable energy resources like wind and solar.

We have ramping concerns, overgeneration concerns, way beyond just peak load reduction, which has been historical use of demand response. We are talking about using demand resources for new things. And the challenge with integrating so many variable energy resources is that the ISO market is about supply and demand, and balancing supply and demand second by second. And if the supply side is going to become much more variable, what is your alternative? You have to get elasticity, flexibility out of your demand side. There's nowhere else to turn. And so somehow this message doesn't seem to ring loud enough, in my opinion, with these IOU applications. But that is imperative that we get this flexibility out of demand side. Everybody's talking about it, but this is the place where it's going to happen where the investment is going to be made to make that happen. And yet, I still see some a lot of the same old same old. However I see some, like Edison's making the transition in their AC cycling to PDR. We see a little bit from PG&E. But it's just -- in my opinion, it's not enough and it's not fast enough.[6]

The incremental approach threatens to leave DR behind as an effective resource tool to integrate renewable resources and support California's 33 percent RPS. Continuing to fashion DR in much the same way it has always been reduces DR to an act of good citizenry and a potential rate relief mechanism for select

[6] Vol 4 Reporters' Transcript at p. 523, line 16- p.525 line 28.

customers, but has little affect making DR a preferential and flexible resource in the loading order .

PG&E says it proposes to transition DR programs to PDR only if the expected transitional benefits to ratepayers, at minimum, equal the expected transitional costs.[7] While the ISO understands that expenditures and budgets must be reasonable, the metric that PG&E seeks to impose is inappropriate and inadequate to meet the loading order goal. What would happen if the state's RPS had this same limitation on the development of wind and solar resources, i.e. "expected transitional benefits to ratepayers, at minimum, or equal to, expected transitional costs"?

PG&E's own discussion of DR in the context of third-party aggregators indicates that it does not apply the proposed metric when comparing its own program costs to third-party aggregator program costs. In explaining why IOU programs might be more expensive than third-party offerings, PG&E claims that one cannot simply look at competitive price –because the Commission imposes certain obligations on the IOUs that are not required of third-party providers.[8] The ISO submits that PG&E is making the same mistake when it compares its traditional programs like BIP to DR integrated in the ISO market. One cannot simply compare prices, because the loading order and RPS impose obligations on today's DR to act as the second leading source for new resource additions.

Finally, the ISO notes that PG&E lambasts ISO's recommendations to look to third-party aggregators for competitive procurement of programs it wants to build in-house; however, when PG&E itself is interested in third-party aggregator participation for its AMP program, it flips its opinion and notes that "the CAISO testimony recommends that the CPUC direct `that the IOUs use

[7] PG&E Opening Brief at p. 55.
[8] PG&E Opening Brief at pp 67-68.

competitive procurement to solicit DR designed to satisfy long term procurement and resource adequacy requirements from aggregators.'"[9] Apparently, PG&E values ISO's opinion and recommendation that DR should be transitioned into the rubric of competition and third-party provision where PG&E has already decided to do so; otherwise, ISO's recommendations should be "disregarded" as "unsupported by evidence."

Finally, PG&E states that CAISO's proposals ignore the customer's perspective on participation in DR programs, citing CLECA's witness Dr. Barkovich that many customers are content to participate in utility-sponsored programs and would not necessarily want to leave them for third-party programs. This begs the question of whether IOU DR programs are so over-market that customers are not even be interested in a counter-offer.[10] Why would customers be so uninterested?

The Commission should consider the impact the resource adequacy proposed decision has on the applications and provide additional time to incorporate its provisions, as necessary

DRA rightly points out that ALJ Gamson's Proposed Decision (PD) in Rulemaking 09-10-032, which further refines the Resource Adequacy ("RA") rules for demand response resources, adopted in D.11-06-022, impacts these applications. DRA states that "[t]wo of the changes adopted in the PD, specifically 1 and 3 above [local dispatchability of demand response if local RA capacity and prohibition of fossil-fueled back-up generation receiving RA credit as demand response] if adopted in the final decision, could have a significant impact on the outcome of the IOUs' 2012-2014 DR program applications

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[9] PG&E Opening Brief at p. 68, quoting from the ISO's testimony (Exhibit ISO-1, at p.11, lines 18-19 (Testimony of John Goodin)).
[10] Vol. 2 Reporters Transcript at p. 306, line 9 to p. 310, line 2.

currently being litigated before the Commission." (DRA Opening Brief at p 53.) The ISO agrees and supports DRA's suggestion that "[s]hould the PD be adopted, DRA recommends the Commission consider a revised schedule for a final decision in IOUs' 2012-2014 DR program applications and consider "bridge funding" for a few months, if necessary." (DRA Opening Brief at p 55.)

Not all demand response must be integrated into the ISO market, but RA qualifying demand response must

CLECA misconstrues the notion that all demand response must be integrated into the ISO market. CLECA asserts that "[t]he Commission must not lose sight of the significant merit of DR that is not bid into the CAISO market and should reconsider its determination that all DR should be integrated into CAISO markets. (CLECA Opening Brief at p. 18.) CLECA paints demand response with overly broad strokes, generalizing it as if it were all the same type and quality. The ISO has been clear that demand response must be integrated into the ISO market in order for it to count as resource adequacy capacity. Resource adequacy resources are high quality, dispatchable resources that are available to the ISO when and where needed. The "available when and where needed" is the Commission's own resource adequacy principle. If a particular demand response resource lacks this attribute, then it should not count as resource adequacy capacity, and, also, correspondingly, should not be required to integrate into the ISO market. For instance, a load forecast modifying dynamic rate, like PG&E's Peak-day Pricing rate, does not have to be integrated in the ISO market. However, it also should not count as resource adequacy capacity since it is not dispatchable where needed. Fundamentally, a demand response program that qualifies as resource adequacy capacity, unlike a dynamic tariff, must be a supply-comparable resource and must be integrated into the ISO market.

CLECA's statements are not only overly generalized and unspecific, but are also inconsistent. All forms of demand response need not be integrated into the ISO market. CLECA states:

> Integrating all DR into the CAISO may have a negative impact on participating customers, leading to reduced participation; such an unintended consequence should be avoided. CLECA accordingly opposes the CAISO proposal to now force all DR into its wholesale markets and strongly recommends rejection of this proposal to now force all DR into its wholesale markets and strongly recommends rejection of this proposal." (CLECA Opening Brief at p 18.)

Again, the ISO has not proposed that all forms of demand response be forced into the wholesale market. Rather, the ISO has been consistent that demand response that qualifies as resource adequacy capacity as a supply-comparable resource must be integrated into the ISO market.

CLECA also raises alarm about treating demand response as a generation comparable resource and its negative impact on customers and the concern of reduced customer participation. Yet CLECA reasons inconsistently on this point. CLECA admits that integrating BIP into the ISO market under the ISO's Reliability Demand Response Product (a "generation comparable" demand resource) does not alter the underlying program characteristics and customers continue on under the program as normal. CLECA states:

> Notably, updating BIP to meet CAISO Reliability Demand Response Product requirements *does not alter the basic program characteristics*. Customers will still commit to a firm service level for one year in exchange for monthly bill credits for on- and mid-peak demand charges, and they will still face stiff penalties should they fail to drop their load down to the firm service level during a BIP event.[3] (CLECA pg. 4, footnote omitted; emphasis added)

In other words, CLECA concedes that converting to a generation comparable demand resource integrated in the ISO market has little to no impact on the underlying BIP program. The ISO envisions that if the IOUs continue to develop retail demand response programs, those retail programs will similarly integrate seamlessly into the ISO market as generation-comparable resources that qualify as resource adequacy capacity with minimal customer dislocation.

Dynamic rates reduce forecast load and are not a resource treated as resource adequacy capacity

CLECA raises the issue of whether rates should vary on a locational basis, stating:

> [T] he CAISO has proposed that dynamic pricing not receive RA credit unless it can be dispatched on a locational basis.[51] Since dynamic pricing is a rate design program, the Commission must decide (and it should not do so in an RA case) whether it wishes its rates to vary on a locational basis, a significant departure from current rate policy." (CLECA Opening Brief at p 21, footnote omitted.)

CLECA makes a very important point about dynamic pricing– it is a rate, not a program. Rates are not supply-comparable demand resources. The ISO agrees with CLECA on this point.

As a rate, dynamic pricing is fundamentally not a supply-comparable resource that is dispatchable when and where needed for a specific megawatt quantity, which is a required principle for a resource adequacy resource under the Commission's resource adequacy program. As such, dynamic rates, such as PG&E's Peak-day Pricing rate, should not qualify as resource adequacy capacity and do not need to be integrated into the ISO market and be locationally dispatchable.

Dynamic rates fundamentally alter the load shape and are more appropriate as an adjustment to the IOU forecast load rather than as a "resource." SCE makes this same argument which the ISO incorporated into its direct testimony on the IOUs 2012-214 demand response applications.

In Volume 1 of SCE's testimony, SCE relates that it does not intend for its Critical Peak Pricing Program to be treated as a Resource Adequacy resource at the outset of the program cycle:

> SCE would also like the Commission to note that SCE currently does not plan to bid CPP or Save Power Day as a Proxy Demand Resource (PDR) in the CAISO markets *because they cannot be locationally dispatched*. As SCE gains experience with these programs, it may consider requesting that the megawatt (MW) load reductions be treated as a reduction in the load forecast rather than as a resource requiring RA counting. At that time, the event hours would not be an issue for RA.[11] (emphasis added)
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> SCE proposes similar treatment for its Save Power Day Program: Save Power Day provides incentives to customers for curtailing their usage during event days. The rebates provided by the program should translate to lower electricity usage by customers. The anticipated change in electricity usage is taken into account when SCE schedules its day-ahead load with CAISO. In addition, Save Power Day is not a program that can be locationally dispatched as required for PDR and RDRP in MRTU. Save Power Day can be considered a "load modifying" DR program rather than a program that would be bid and dispatched through PDR or RDRP in MRTU.[12]

The ISO agrees with SCE's logic that, where demand response programs lack the ability to be dispatched when and where needed, those programs should not be counted for resource adequacy. The ISO concurs with SCE's comment above that, in such situations, the program is more appropriately treated as a mechanism for forecast reduction instead of resource adequacy, which can lower the IOUs procurement needs on the day the program is called.

Dynamic rates will ultimately reshape an IOU's load profile and the overall system load profile as consumption behaviors change. Dynamic rates are load modifying tariffs not demand response programs. Peak demand will decrease if majority customers are exposed to higher prices during peak periods. Since peak demand sets the resource adequacy capacity requirement, reduced

[11] Exhibit SCE-1 SCE Amended Testimony Volume 1, at p 14. (Testimony of L.Oliva)
[12] Exhibit SCE-2 SCE Amended Testimony, Volume 2 at p 35. (Testimony of B. Anderson et al)

peak consumption will lower the resource adequacy capacity requirement. If IOU dynamic rates, like Peak-day Pricing or Save Power Day, do as they claim, then, counter to PG&E's claim, there will be no need to "replace" RA capacity since peak-demand, along with the resource adequacy requirement, will decrease. Thus, PG&E's argument is unsubstantiated and counter-intuitive to the fundamental design and intent of dynamic rates. The Commission should reject PG&E's argument that "[i]f the PD is not revised, PG&E will be required to seek an exemption for its dynamic rate programs or replace the RA provided by these programs."[13] No exemption is required. No RA capacity need be replaced. If treated properly treated and categorized as a load modifier, debates about integrating dynamic rates as a supply-comparable resource in the ISO market go away and the need to dispatch locationally is moot.

11.2. INTEGRATION WITH CAISO MARKETS

The Commission should use this application cycle to integrate demand response into the ISO market

PG&E states in its opening brief that "PG&E proposes to transition DR programs to PDR only if the expected transitional benefits to ratepayers, at a minimum, equal the expected transitional costs."[14] However, PG&E will only view the matter from the perspective that it must build in-house capability to integrate demand response into the ISO market. Poignantly, PG&E notes that "PG&E's and SCE's analyses indicate that it would take millions of dollars to bid all programs as PDR, RDRP."[15]

These costs will be placed into rate base under the IOU in-house approach. In contrast, a third-party aggregator would have no ability to do so. If an

[13] PG&E Opening Brief at p 6.
[14] PG&E Opening Brief at p 55.
[15] PG&E Opening Brief at p 58.

aggregator provides the product, the infrastructure and IT costs are not built into PG&E's rate base. And if the aggregator does not perform, then contract provisions within an aggregator contract itself can trigger remedial action (i.e. incentive payments are reduced). [16] In contrast, If PG&E or SCE builds in-house capability to integrate DR into the ISO market, those costs and risks are spread to all ratepayers with no non-performance provisions. Additionally, unlike a California utility, a third-party aggregator can leverage its capital costs across all markets in the country where it does business. And, in the competitive marketplace there is much incentive to be efficient and cost-effective.

PG&E states:

> Further, Mr. Goodin's prepared and oral testimony appears to imply that aggregators can provide PDR more cost effectively than the IOUs' programs and that through aggregator contracts somehow the IOUs could entirely shift the risk of IT cost overruns on the aggregators.[17]

Similarly, SCE states:

> CAISO seems to think that these costs [IT infrastructure and integration costs] can be avoided by having non-IOU's do this work.[433] CAISO doesn't even seem to understand that third parties would logically include their IT infrastructure costs to bid their product as PDR in their contract price, and therefore, the IOU's ratepayers would be picking up the tab there as well.[18]

This mischaracterizes Mr. Goodin's testimony. His testimony conveys the points stated above, that the *aggregator's IT* costs are not transferred to rate base and to all ratepayers as are the IOUs. This critical cost allocation difference cannot be glossed over.

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[16] PG&E makes the point in support of aggregator contracts in its opening brief that "Further, as DRA itself acknowledges, to the extent that any aggregator does not perform, the incentive payments are reduced according to the contract terms, thus making the ratepayers whole for any non-performance during the event" .(PG&E Opening Brief at p 55.)

[17] PG&E Opening Brief at p 63.

[18] SCE Opening Brief at p 76, footnotes omitted.

RA counting should not wait for another program cycle and should be addressed in this proceeding in accordance with the proposed decision

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:

- Creating a specific Maximum Cumulative Capacity (MCC) bucket for demand response;[19] and

[19] 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.)

- 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."[20]

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.[21]

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.[22]

11.3. DEMAND RESPONSE MARKET COMPETITION

The existing demand response business model must change

The ISO is concerned about the perspective and opinion demand response providers have about the state of demand response in California. The demand response provider community is concerned about two fundamental issues:

- Regulations concerning the direct participation of demand response in the wholesale market
- Access to capacity payments (aka resource adequacy capacity)

[20] Exhibit ISO-1 Direct testimony of witness John Goodin, at p 14.
[21] Resource Adequacy Proposed Decision at p. 7.
[22] Resource Adequacy Proposed Decision at p. 9.

Because these two issues seem intractable and have been talked about for years yet remain unresolved, the demand response provider community conveys pessimism about the California market and their ability to competitively provide demand response products and services. It is telling when a demand response provider's testimony states a desire for opening the market to competition, but understandably, petitions the Commission to hold onto and promote utility-controlled demand response contracts. Unfortunately, utility contracts are the only game in town and are the only access demand response providers have to revenue in California. Thus, demand response providers must support utility contracts to profitably operate in California. North American Power Partners aptly makes these points in its opening brief stating:

> NAPP looks forward to the opportunity to provide new services through wholesale energy and ancillary services (AS) markets and is eager for direct participation in the CAISO markets to be fully realized to provide the greatest benefits to California ratepayers.[41] … Integration into CAISO's wholesale market is not only a matter of developing and adopting rules but also, Commission authorization of third party aggregators' direct participation must take place.[42] *During the next three-year program period, it is doubtful we will see resolution of the immediate issues within all the applicable venues or that the appropriate regulatory hurdles will be overcome*, surely not in time for the Commission's consideration of the IOUs' 2012-2014 DR applications. Without the ability for aggregators to directly participate in the immediate future and with the threat of eliminating opportunity to enter into bilateral DR contracts, there is tremendous uncertainty for third party aggregators. Bilateral contracts in this proceeding are essential to provide DR aggregators with regulatory assurance and the opportunity to do business.[43] In the absence of any comparable opportunity at the CAISO, the Commission must authorize and direct the IOUs to procure new DR contracts that can be bid in to the CAISO market.[44]" (NAPP Opening Brief at pp 16-17; emphasis added; footnotes omitted)
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> …
>
> For aggregators and their customers, capacity payments are important because they provide a long-term revenue stream that can offset the cost of developing, managing and compensating customers who commit to reduce loads as reliability and energy resources. It should be noted that resources developed through the CAISO structures are ineligible to qualify for capacity payments as a RA resource. With regard to the Commission's RA program,

> the rules for direct participation do not address DR through DR providers that qualifies for RA. As a result, these DR resources will lose value to ratepayers as a RA long-term reliability resource. (NAPP Opening Brief at p 20.)

As NAPP clearly conveys, a competitive demand response market is stymied in California since demand response providers cannot offer retail demand response programs, they have no access to resource adequacy capacity payments and they are largely prohibited from enrolling customers in wholesale demand response products. At this juncture and under current Commission policy, all demand response activity must go through the IOUs' front door. This demand response business model must change. The Commission must develop policies that allow a competitive demand response market to flourish in California.

Competitive solicitation should be the default procurement method for demand response

PG&E conveys that it must retain the ability to build in-house demand response so that it can address transmission and distribution issues. PG&E states "[t]he Commission should reject the CAISO's proposals to have aggregators be the sole source DR providers.262/ PG&E, in its roles of LSE and UDC, can play a significant role in the provision of DR, including integration of DR resources in its transmission and distribution planning and in resource planning and operations." (PG&E Opening Brief at pp 62-63.)

The Commission should clearly reject the argument that the IOU must build demand response to address its own T&D issues and include it in its planning process. There is no reasonable argument why demand must be built "in-house" versus procuring through competitive solicitation so that demand response can address a local T&D concern and be incorporated into the IOU's planning process. It is unlikely the Commission would accept a similar argument if the utility proposed to build generation for similar reasons. In fact, the ISO would argue that through competitive solicitation, the IOU can easily specify the nature of the demand response product it desires and include a performance penalty if the demand response provider fails to deliver the contracted-for resource attributes. This puts the performance risk, or lack thereof, on the third-party demand response provider, not on ratepayers.

Fundamentally, like generation procurement, the Commission should require that competitive solicitation occur first before a utility "builds" demand resources. The IOU should not be the sole proprietor of all demand response products, services and contracts. The Commission's policy trajectory should be the competitive solicitation of all demand response.

14. REVENUE REQUIREMENT AND COST RECOVERY

The Commission Should Require the IOUs to procure a certain portion of their DR portfolio through demand response providers

The cost of IOU demand response programs are imbedded in the IOUs rate base, spreading the costs among all bundled customers, whether those customers participate or not. This ability to "peanut butter" costs over all customers can be seen as a competitive advantage over third-party aggregator programs. The Commission has recently recognized this in allocation in its recent decision on Plug-In Electric Vehicles, D.11-07-029.[23] There, the Commission declined to adopt an IOU proposal to allocate the utility costs of providing PEV meters to the "general body of ratepayers," noting that this could confer an unfair competitive advantage on the IOUs:

[23] Phase 2 Decision Establishing Policies to Overcome Barriers to Electric Vehicle Deployment and Complying with Public Utilities Code Section 740.2

> We further find that placing the costs of existing separate Electric Vehicle meters on the general body of ratepayers may result in an unfair advantage for utilities relative to the non-utility electric vehicle service providers. In making this finding, we agree with the competitiveness concerns raised by the EVSP Coalition and Green Power Institute. We also rely on Pub. Util. Code § 740.3(c), which establishes that the Commission's policies shall "… ensure that utilities do not unfairly compete with nonutility enterprises." [24]

The Commission should consider this issue of IOU competitive advantage though IOU ability to embed demand response program costs to its general body of ratepayers. To encourage development of third party demand response provider entry and competition, the Commission should require the IOUs to procure a certain percentage of MW value of its demand response portfolio through third party providers.

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[24] Id. at p. 46.