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 (Filed September 19, 2013)

OPENING TESTIMONY OF ENVIRONMENTAL DEFENSE FUND ON PHASE TWO AND PHASE THREE ISSUES

WITNESS:
Steven Moss
Partner, M.Cubed
2325 Third Street, Suite 344
San Francisco, California 94114
Phone – 415.643.9578
steven@moss.net

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I. INTRODUCTION

The Environmental Defense Fund ("EDF") respectfully submits the following Testimony[1] in response to the California Public Utilities Commission's ("Commission" or "CPUC") "Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings," R.13-09-011, issued on April 2, 2014 ("DR Testimony Guidance").[2] EDF has been an active participant in this proceeding, including attending workshops and submitting comments.

EDF's predominate interest in this case is to ensure that demand response ("DR") programs and tariffs are given the opportunity and support necessary to create benefit to the state, electricity grid, and ratepayers by providing services that would otherwise be delivered by environmentally-damaging and expensive fossil fuel facilities. As discussed in detail further

[1] Joint Assigned Commissioner and Administrative Law Judge Ruling and Revised Scoping Memo Defining Scope and Schedule for Phase Three, Revising Schedule for Phase Two, and Providing Guidance for Testimony and Hearings, R.13-09-011, at 6 (filed April 2, 2014) ("Testimony Guidance Scoping Ruling"), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M089/K323/89323807.PDF. The Testimony Guidance Scoping Ruling identified issues that parties may consider in their Opening Testimony, and additionally stated that Opening Testimony "may address the issues in general." This Testimony addresses a number of the identified issues, while also providing comment to pertinent topics, generally.

[2] Steven Moss serves as the witness for this Testimony, with qualifications and experience provided in Attachment A to this Testimony.

below, providing commensurate opportunities, value streams, alignment with local and system needs, and accurate forecasting for both load modifying and supply resource DR programs and tariffs is essential to reach this goal. As the grid continues to evolve towards becoming smarter, cleaner, and more customer-oriented, DR should play an increasingly important role in delivering value to the grid, investor-owned utilities ("IOU"), ratepayers, and the environment. Improvements in how DR is valued, managed, deployed, dispatched, and forecasted would provide California with a powerful tool in furthering the efficient and environmentally sustainable delivery of electricity and deferring otherwise expensive infrastructure investments.[3]

II. PURPOSE OF TESTIMONY

Although significant progress has been made over the past ten years to nurture the development and deployment of DR, more work must be done to determine how best to value, forecast, and align load modifying and supply resource DR with system and local needs. If given the opportunity, a wide range of DR can contribute to the grid in a number of different ways. This testimony details how DR can, with proper structure and form, deliver needed benefits, including:

- *Addressing short-term imbalances between supply and demand.* Although natural gas facilities are currently given strong preference to address the need for "flexible capacity,"[4] over the next five years DR, including storage and technology-enabled DR (such as automated DR), should become a primary tool to address hours-long supply and demand imbalances.[5] The need to address short-term imbalances between supply and

[3] Moreover, DR, when properly forecasted and utilized, can enhance the value of other services and technologies, including renewable energy, energy storage, and distributed generation.
[4] These facilities are better able to meet existing requirements for lengthy availability, and can access revenue streams not available to DR.
[5] Technology-enabled DR can play a role in minute-by-minute fluctuations caused by a passing cloud or change in wind speeds, but this is not likely this resources' optimal way to beneficially contribute to the grid.

demand goes well beyond traditional efforts to address demand peaks. As the state of California's grid changes, it is imperative that predicted system imbalances and distribution congestion are met head-on; DR represents one of the best tools to do so. A number of factors can prompt these imbalances, with gaps between supply and demand being most significant.[6] Supply resource DR is ideally suited to address imbalances – it can be aggregated to provide bursts of flexibility as needed to address these hours-long imbalances. Load modifying DR likewise works to remedy this issue, by changing load shapes over the long term. New flexible capacity programs, including automated DR, on the supply resource side; and load shaping tariffs, on the load modifying resource side, can serve to mold load profiles in ways that reduce the need for flexible capacity and address those requirements when they emerge. From this perspective, a goal in this proceeding should be to deploy load modifying DR so as to reduce requirements for flexible capacity over the long run, and maximize the amount of short-term, or flexible, procurement needs that can be met by DR by 2017.[7]

- *Reshaping the grid*. DR that can permanently modify load, such as time-variant tariffs – which, if effectively crafted, will induce beneficial storage, automation, and information technology into the market. These rates should increasingly be used to provide ratepayers with transparent price signals about the costs of using electricity in a given

[6] Other sources of imbalance include intermittent excess or shortfalls in renewable generation caused by changes in the weather, ramping needs induced by declines in photovoltaic production during late-afternoon and twilight hours, and abrupt disruptions caused by a transmission or generation failure.
[7] *See* Opening Comments of Sunverge Energy, Inc. on Assigned Commissioner's Ruling Proposing Storage Procurement Targets and Mechanisms, R.10-12-007, at 3-4 (filed July 3, 2013), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M075/K768/75768265.PDF In discussing the linkage between load modifying DR and storage, the comment states that "[d]ue to the nature and costs of various storage technologies, some solutions are more cost effective at shifting energy and some solutions are more cost effective at offsetting demand. Therefore, we propose the commission coordinate the exploration of unbundling residential rate structures to encourage customer management of demand during peak periods with storage solutions that are co-located with solar behind the utility electric meter."

place and time. This advancement would give ratepayers the opportunity to reduce their bills by taking advantage of low rates during periods of electricity over-supply. This would reduce demand's contribution to steep afternoon ramping periods, thereby addressing the most significant contributor to flexible capacity needs, in turn reducing grid costs, including to the environment.[8] From this perspective, a proceeding goal should be to support active, enthusiastic, and experimental DR tariff (and associated enabling device) development and deployment that, over time, reflects as closely as possible the full costs of electricity provision at a given hour, and within a specific distribution planning area, substation, and circuit.

- *Reducing distribution costs*. Both load modifying and supply resource DR can be used to reduce pressure on the distribution system, by flattening circuit- and substation-level load. This, in turn, can serve to defer the need for distribution-related investment. Distribution-level loads can likewise be molded through cost-based tariffs and programs that fully reflect differences by time and place. This could initially be done based on coincident distribution peaks, and ultimately expanded to consider the costs associated with both coincident and non-coincident peaks. As explored more fully below, San Diego Gas and Electric Company ("SDG&E") has already proposed to develop this approach – calculating day-ahead distribution level costs and providing associated price signals to their electric vehicle ("EV") customers, as part of their Vehicle Grid Integration ("VGI") pilot proposal.[9] Regardless, the California Independent System Operator ("CAISO") and the IOUs should use transparent information about the

[8] Third parties could play an important part in providing this opportunity, however the method to create access for such parties remains an open issue.

[9] Application of San Diego Gas & Electric Company (U 902 E) for Approval of its Electric Vehicle-Grid Integration Pilot Program, A.14-04-014 (filed April 11, 2014), http://www.sdge.com/regulatory-filing/10676/sdge%E2%80%99selectric-vehicle-grid-integration-pilot-program.

implications of load modifying and supply resource DR in the form of granular forecasting and identification of the value of capacity at a given time and place, so they can properly plan their ends of the grid. This information would also be beneficial for third parties, to the extent that it could enable them to offer beneficial DR products.

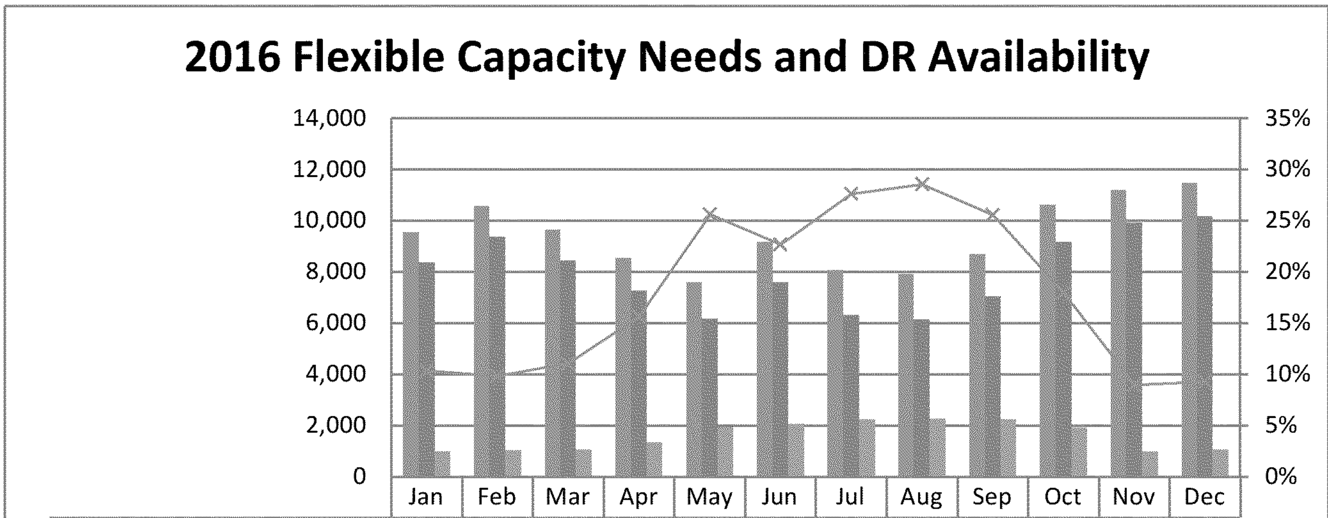
III. DISCUSSION

a. Goals for Demand Response

Refining DR for System Needs. DR, in the form of interruptible programs and voluntary TOU rates, has been used as a tool to address supply shortfalls for decades. However, up until now this tool has largely been a blunt one. On the supply resource side, the latest iteration of DR programs emerged out of the 2001 energy crisis as a method to retain customers and address occasional short-term supply gaps, a pattern that replicated pre-crisis interruptible programs. Today, utility-managed supply resource DR programs often cannot be directly accessed by CAISO, with triggers oriented towards providing peak, rather than flexible, capacity. With the more recent and pressing requirement for flexible capacity, supply resource DR improvements must be made to address present and future needs.

The need for modification is apparent: as illustrated in the figure, CAISO expects the greatest demand for flexible capacity in December, one of the lowest months of DR availability for all three utilities.[10] For example, Pacific Gas and Electric Company's ("PG&E") collective DR programs offer the most load in July, Southern California Edison Company ("SCE") in August, and SDG&E in September. Peak DR capacity is certainly valuable to the system, but so too, increasingly, is flexible capacity.

[10] The time of day when DR is available is also not synched with system needs.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Flex_Req_2016	9,550	10,589	9,656	8,560	7,596	9,166	8,072	7,934	8,706	10,610	11,209	11,477
Max of 3_hr_ramp_2016	8363	9367	8450	7275	6176	7600	6334	6150	7044	9177	9940	10190
Total DR Available 2016	992.4	1045.8	1072.2	1342.7	1950.1	2082.6	2233.8	2267.2	2229.9	1914.4	1008.5	1070.4
DR as % of Flex_req	10%	10%	11%	16%	26%	23%	28%	29%	26%	18%	9%	9%

On the load modifying side, newly deployed meters, associated information, and billing technology can unlock a previously constrained DR resource. Currently, the amount of load shifting and curtailment created by the time-variant program and rates offered by the IOUs is quite modest. In PG&E's service territory, less than 350 megawatts ("MW") of load shifting is expected from time of use ("TOU") rates in 2016, representing under two percent of total peak load.[11] Together, the IOUs' three DR programs oriented towards residential customers – Smart Rate, SmartAC, and TOU – produce just 128 MW of load, less than two percent of demand from the utility's largest customer class.

SCE operates DR programs oriented towards residential customers – including the Summer Discount Plan Residential – that produce more than double the load as PG&E, but far more potential exists. This potential has been created by large investments in smart grid

[11] California Energy Commission, *California Energy Demand 2014-2024 Final Forecast, Volume 2: Electricity Demand by Utility Planning Area*, Chapter 1: Pacific Gas and Electric Planning Area (January 2014), www.energyca.gov/2013publications/CEG200-2013-004/CEC-200-2013-003-V2-CMF.pdf.

technologies and demonstrated by numerous studies that indicate the potential and desirability of greater time-variant tariff penetration levels (and associated load shifts). For example, Sacramento Municipal Utility District ("SMUD") recently instituted a dynamic pricing pilot, in which certain customers were defaulted to a TOU pricing rate, with the ability to opt out of the rate structure. Notably, less than 10 percent of customers choose to do so. Effective education and marketing, such as targeted web portals for customers and increased attention to customer service enabled SMUD to support its customers and make the benefits of efficient energy use transparent, viable, and desirable.[12]

Without a fully effective complement of DR available to grid managers and ratepayers, energy users are largely unaware of the value of electricity in a given time and place, and as a result have no knowledge or incentive to respond to needs as they arise. This condition:

> …contributes to blackouts in times of scarcity and to the inability of the market to determine the market-clearing prices needed to attract an efficient level and mix of generation capacity. Moreover, the problems caused by this market failure can result in considerable price volatility and market power that would be insignificant if the demand-side of the market were fully functional.[13]

Likewise:

> Suppose electricity markets did not suffer from demand-side flaws. In particular, suppose demand is sufficiently responsive to prices, such that the wholesale electricity market always cleared. Then, the market would be perfectly reliable: if supply is scarce, the price would rise until there is enough voluntary load reduction to absorb the scarcity. Consumers would never suffer involuntary rationing.[14]

Transparent price signals motivate consumers to reduce electricity use during high cost periods. Even if only a portion of consumers respond, together they all would enjoy lower rates.

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[12] *Dynamic Pricing Saves Energy and Costs at SMUD.* Green Tech Grid (July 15, 2013), http://www.greentechmedia.com/articles/read/Dynamic-Pricing-Saves-Energy-and-Costs-at-SMUD.

[13] Cramton, Peter, *et al.*, *Capacity Market Fundamentals*, at 1 (May 26, 2013), www.cramton.umd.edu/papers2010-2014/cramton-ockenfels-stoft-capacity-market-fundamentals.pdf.

[14] *Id.* Note that price signals neither should nor need to disrupt the existing regulatory compact to safeguard low income households from adverse bill consequences, which can both be shielded from these prices and offered opportunities to take advantage of them.

For example, a California study found that a 2.5 percent reduction in demand statewide could lower wholesale prices by 24 percent; a 10 percent demand reduction could cut them in half during periods of extreme scarcity.[15] Stated differently, "DR benefits not only the person reducing consumption, but also all other ratepayers and the grid as a whole."[16]

DR as a System Resource. This proceeding coincides with a tremendous opportunity for DR, created by now ubiquitous access to advanced utility metering infrastructure, the emergence of handheld apps, and other technologies that can be used to convey information, prices and dispatch directives, and the need for sharper utility management tools prompted, in part, by the extraordinary success of renewables. DR, in tandem with renewables, storage, and energy efficiency, can provide many services to the grid, substantially reducing the need for new power plant procurement - an opportunity that California should be ready and poised to seize.

Leveraging DR for System Benefit. Grid advances, and the rapid emergence of the adverse consequences of global climate change, have created a pressing need to leverage DR to the benefit of the IOUs, ratepayers, and environment. Changing load shapes and pressures on the distribution system are prompting the need for next generation load management tools. Smart grid investments have opened pathways for consumer-oriented innovation. The successful deployment of renewables has induced a concomitant need to manage intermittent resources in ways that maximize their environmental value.

Within this context, it is important to note that California does not face an immediate flexible capacity-related reliability problem, nor is it likely to for at least several more years.

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[15] Moore, Taylor, *Energizing Customer Demand Response in California*, Electric Power Research Institute (Summer 2001).

[16] Reulet, Sandra, *Demand Side Management and Peak Load Reduction*, New York State Public Service Commission (2013), www.naruc.org/international/Documents/SandraReulet_Demand_Side_Management_and_Peak_Load_Reduction_-Sep28_1.30.pdf

The state has access to an estimated 30,000 MW of excess fossil fuel capacity, a greater than 50 percent margin above system-wide peaks.[17] Current flexible capacity surpluses should provide regulators with the confidence to build towards a new energy era, in which DR and other sustainable resources play a central role in managing grid equilibrium and associated reliability. This approach would dovetail with the CPUC's intent to consider new flexible capacity requirements after 2017, which should be crafted to match with next generation demand response policies.[18]

Over the next two years, the CAISO has estimated that upwards of 9,000 and 11,500 MW of three hour net load ramps will emerge on the system monthly.[19] Yet, the three IOUs estimate that they will only have roughly 2,300 MW of total DR available[20] during this period, including both load modifying and supply resource DR tariffs and programs.[21]

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[17] Kevin Woodruff, *Planned Remarks on behalf of The Utility Reform Network*, prepared for the Federal Energy Regulatory Commission Technical Conference on Flexible and Local Resources Needed for Reliability in the California Wholesale Electric Market, AD 13-5-000 (July 31, 2013).

[18] *See* Decision Adopting Local Procurement Obligations for 2014, a Flexible Capacity Framework, and Further Refining the Resource Adequacy Program, R. 11-10-023 (issued July 3, 2013) (OIR, Final Decision), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF

[19] California Independent System Operator Corporation Submission of Preliminary 2014 Flexible Capacity Needs Assessment, R. 11-10-023, at 7, 9 (filed April 1, 2014), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M090/K098/90098962.PDF.

[20] Based on 1-in-2 weather conditions on July peak load days.

[21] California Public Utilities Commission, R. 13-09-011, *Pacific Gas and Electric Company (U 39 E) Compliance Filing Pursuant to Load Impact Protocol Filing Requirements:* Pacific Gas and Electric Company, *Executive Summary: 2014-2024 Demand Response Portfolio of Pacific Gas and Electric Company*, Appendix B (OIR) (April 1, 2014), https://www.pge.com/regulation/DemandReponseOIR-2013/Other-Docs/PGE/2014/DemandResponseOIR-2013_Other-Doc_PGE_20140401_300583.pdf; California Public Utilities Commission, R. 13-09-011, *Southern California Edison Company's (U 338-E) Compliance Filing Pursuant to Load Impact Protocol and Notice of Availability of Statewide and Local Demand Response Load Impact Reports:* Southern California Edison Company, *Appendix A – Executive Summary: 2014-2024 Demand Response Portfolio of Southern California Edison Company* (OIR) (April 1, 2014), https://www.pge.com/regulation/DemandReponseOIR-2013/Pleadings/SCE/2014/DemandResponseOIR2013_Plea_SCE_20140401_302743.pdf; California Public Utilities Commission, R. 13-09-011, *Load Impact Reports, Executive Summary, and Tables of San Diego Gas & Electric Company (U 902 E):* San Diego Gas & Electric, *2013 Impact Evaluation of SDG&E Non-Alert PTR Population* (OIR) (April 1, 2014), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M089/K641/89641661.PDF/

Current DR programs illustrate the potential for the resource in the state. For example, in 2013 roughly 120,000 residential class customers were enrolled in PG&E's SmartRate critical peak pricing program. On its own, the program was able to induce low double-digit demand reductions when it was triggered; curtailment levels reached as high as 30 percent when combined with the SmartAC program.[22] Similarly, PG&E's voluntary TOU rates, with just 60,000 residential customers, has demonstrated an ability to shift load by up to 30 percent, with an expected average load reduction of nine percent.[23] Although SmartRate has grown rapidly over the past year, it still serves less than one percent of households in the utility's service territory. While PG&E is predicting no growth in its existing TOU programs, expanding and fine-tuning time-variant rate options would allow them to play a much bigger role in reducing the need for flexible capacity.

The Federal Energy Regulatory Commission ("FERC") found that DR that included just a small-number of price-responsive programs could offset nine percent of peak demand. Numerous pilots and emerging tariff programs similarly demonstrate that at least this level of contribution is possible.[24] The gap between goals contained in the 2008 *Energy Action Plan* and current reality likewise showcases the need for greater DR penetration, with the Plan stating:

> To meet our policy goals, it is imperative that we develop understandable and transparent dynamic pricing tariffs and demand response programs that operate with these tariffs. The first *EAP* set a goal of five percent of peak demand to come

[22] Nexant, *2013 Load Impact Evaluation of Pacific Gas and Electric Company's Residential Time-based Pricing Programs*, prepared for Pacific Gas & Electric Company (April 1, 2014).
[23] *Id.*
[24] *See, e.g.,* Federal Energy Regulatory Commission, *Staff Report: A National Assessment of Demand Response Potential* (June 2009), https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf; *See, e.g.,* Karen Herter, *et al., The Effects of Combining Dynamic Pricing, AC Load Control, and Real-Time Energy Feedback: SMUD's 2011 Residential Summer Solution's Study,* 6 Energy Efficiency 641 (November 2013), link.springer.com/article/10.1007%2Fs12053013-9209-7; *See* Federal Energy Regulatory Commission, *Staff Report: Assessment of Demand Response and Advanced Metering* (Oct. 2013), https://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf.

> from price response from consumers by 2007. We are nowhere near that goal and must reinvigorate our efforts in this area.[25]

Five years later, all of the IOUs programs combined have yet to reach the five percent goal.[26] Leveraging DR to meet both general targets and specific system needs is required. For example, load modifying tariffs, if effectively implemented, correctly crafted, and well marketed, will be able to meet the majority of CAISO's estimated ramping requirement, while reducing pressure on the distribution system. Put differently, load modifying DR, if properly utilized (with associated enabling devices) could sufficiently change the shape of demand to largely resolve, or at least reduce, the need for flexible capacity.

In this respect, determining how DR can be used to meet multiple needs is a baseline and essential inquiry – particularly in respect to how the CPUC should nurture the variety of DR required to meet an emerging diversity of local and system needs. Load modifying DR can and should be deployed to resolve specific forecasted issues, such as "Category I" ramping needs (see below). This is especially the case because demand – more than renewable intermittency – is responsible for 93 to 99 percent of ramping needs, depending on the time of year.[27] Load modifying DR is especially well suited to address the ramping from demand itself, reducing the need for costly and polluting power plants.

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[25] California Energy Commission, *2008 Update Energy Action Plan* (February 2008), http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF.
[26] Data from difference sources, however, suggests that DR could represent a slightly larger percentage (from four to six percent) of peak load. *See* Federal Energy Regulatory Commission, *Staff Report: Assessment of Demand Response and Advanced Metering* (Oct. 2013), https://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf.
[27] California Public Utilities Commission, R.11-10-023, *California Independent System Operator Corporation Submission of Preliminary 2014 Flexible Capacity Needs Assessment* (April 4, 2014).

Matching DR to System Needs. CAISO and CPUC Energy Division analyses[28] suggest one path that would separate DR products into three main tranches.[29] The flexibility needs required in each of these tranches, as codified in Resource Adequacy ("RA") proceedings,[30] could serve as the basis to determine demand response load goals, as follows:

Category 1 (Base Flexibility): This reflects operational needs as determined by the magnitude of the largest three-hour secondary net-load ramp, which amounts to an estimated 3,800 to 7,600 MW in 2015, with significant seasonal variations. The Energy Division has proposed that needs in this category be met with 17 hour products, which is likely beyond the capacity of any but the largest aggregation of technology-supported DR.[31] However, the need for base flexibility could be significantly diminished by reshaping loads through load modifying DR, such as time variant rates, that shift demand away from Category 1 ramping periods, and towards periods when excess electricity is available.

For example, tariffs could be crafted to match with grid operation needs, modified by area-specific (e.g., distribution) coincident peak benefits. That is, time variant rates could be designed to address ramping needs, but based on targeting specific nodes of distribution congestion, as a way to maximize demand response benefits. If, for instance, 80 percent of the desired base flexibility can be secured by effectively offering time variant rates in one-third of the distribution planning areas statewide, bolstered by enabling devices and energy efficiency programs, then that should be the adopted Commission strategy.

[28] California Public Utilities Commission Energy Division, *Staff Proposal on the Implementation of the Flexible Capacity Procurement Framework* (April 9, 2014).

[29] The manner in which this issue is resolved should be an open question, with the CAISO and CPUC Energy Division analyses serving as one option.

[30] *See* Decision Adopting Local Procurement Obligations for 2014, a Flexible Capacity Framework, and Further Refining the Resource Adequacy Program, R. 11-10-023 (issued July 3, 2013) (OIR, Final Decision), http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF

[31] California Public Utilities Commission Energy Division, *Staff Proposal on the Implementation of the Flexible Capacity Procurement Framework* at 15 (April 9, 2014).

Category 2 (Peak Flexibility): This reflects operational needs as determined by the difference between 95 percent of the maximum three-hour net-load ramp and the largest three-hour secondary net-load ramp, estimated at from 400 to 3,500 MW in 2015, with June forecasted to have the greatest need.[32] Energy Division Staff recommends that this category be addressed through five hour products, which lends itself to utility-level critical peak pricing tariffs, as well as auction-based DR programs.[33] In workshops in this proceeding, CAISO staff acknowledged that as new DR products emerge, and confidence in them increases, required product lengths could shrink to two hours or less, an important characteristic the Commission should review as part of future RA proceedings.

Category 3 (Super-Peak Flexibility): This reflects operational needs as determined by five percent of the maximum three-hour net-load ramp of the month, which is estimated at 300 to 500 MW in 2015.[34] Energy Division recommends a five hour product for this category as well, the length of which, like Category 2, should shrink over time.[35] Once barriers are removed and a fully mature DR market has been nurtured, this need could be readily met with auction-based DR programs.

CAISO ultimately intends to establish flexible capacity needs in each category seasonally, based on additional data and analysis. These seasonal differences should run throughout all types of DR programs and tariffs on both the supply and load modifying side. While seasonal definitions would be influenced by local conditions, it appears that June and November may merit special

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[32] California Public Utilities Commission, R.11-10-023, *California Independent System Operator Corporation Submission of Preliminary 2014 Flexible Capacity Needs Assessment* (April 4, 2014).
[33] California Public Utilities Commission Energy Division, *Staff Proposal on the Implementation of the Flexible Capacity Procurement Framework* (April 9, 2014).
[34] California Public Utilities Commission, R.11-10-023, *California Independent System Operator Corporation Submission of Preliminary 2014 Flexible Capacity Needs Assessment* (April 4, 2014) at 12.
[35] California Public Utilities Commission Energy Division, *Staff Proposal on the Implementation of the Flexible Capacity Procurement Framework* (April 9, 2014).

attention as "bonus" DR months, potentially triggering additional payments to participants, higher peak/off-peak and critical peak pricing differentials, and/or "seasonal specials."[36]

The above approach to developing DR goals is one possible method to match system needs with DR program capabilities. Base flexibility can, at best, be met by only the very largest of supply resource DR programs, which appear, moreover, naturally better suited to meet peak and super-peak flexibility needs. On the other hand, load modifying DR and retail level auto-DR programs have substantial potential to contribute thousands of megawatts to Category 1 load shifting and curtailment.

Such a strategy properly follows the CPUC-driven policy evolution of DR programs over the past ten years. For example, statewide rollout of smart meters – which in large part were intended as a means to usher in a new era of what is now called DR – supported wider introduction of critical peak pricing and other dynamic rates, most recently resulting in saturation of TOU rates among non-residential customer classes. Likewise, following Commission and State Legislature guidance, the IOUs have proposed to offer the next generation of residential TOU rates, either on a voluntary or default basis, by 2018.

Adoption of the above or similar approaches would reflect an important step to ensuring that load modifying and supply resource DR are provided with commensurate opportunities relative to one another, and as compared with fossil fuel resources. It is the opposite of siloing, instead matching the appropriate remedy to cure the relevant problem: load modifying strategies are best suited to long-term "base" load curve reshaping, while supply resource DR can address intermittent needs. Equality of opportunity will only be realized if both sides of the bifurcation are given equal access to perform the grid functions for which they are best suited.

[36] For example, one month-only DR programs can be designed and implemented during targeted months, and marketed as "summer savings," or "fall back into energy savings," similar to current "Summer Saver" programs.

While tracing opportunities will help induce greater DR deployment, barriers to entry must also be removed and proper incentives adopted, including enabling DR providers to receive the full value of the services they provide, and accurately forecasting DR benefits to the grid. Equality of opportunity provides, moreover, a means to a greater end: a more efficient, cleaner system that uses DR resources when and where they are best suited. Ensuring commensurate treatment of load modifying and supply resource DR should thus be understood as a way to best allocate resources.

As noted, to realize a more efficient allocation of resources, barriers to entry must be removed for supply and load modifying DR resources. Under current rules, there is little economic incentive or pressure created by market competition to develop load modifying DR. IOUs are offered no direct financial inducements to adopt load modifying tariffs and programs. Absent tariffs or contracts, there are minimal reasons for third parties to vend enabling devices that help ratepayers statically or dynamically shift their electricity use to lower cost periods. Shrinking this value gap is a pressing issue before the CPUC, which should be addressed in this proceeding – the value must be transparent to IOUs, ratepayers, and the market to motivate needed action.[37]

This issue is magnified by current regulatory approaches to both demand forecasting and load modifying DR development. Load modifying DR can only influence capacity decisions if the effects of these initiatives are reflected in California Energy Commission ("CEC") forecasts. However, neither these forecasts nor the IOUs' sales or distribution planning estimates fully incorporate measurements of demand elasticities. As a result, they may not accurately represent

[37] Said differently, "…as long as demand remains rather inflexible it cannot fully mitigate adequacy problems at scarcity events." Cramton, Peter, et al., *Capacity Market Fundamentals*, at 13 (May 26, 2013), http://www.cramton.umd.edu/papers2010-2014/cramton-ockenfels-stoft-capacity-market-fundamentals.pdf.

future load shapes, particularly during times of increasing tariff change, thereby leading to excessive calls for additional capacity.

Likewise, outside of Rate Design Window ("RDW") filings, tariffs are typically adopted in the second phase of General Rate Cases ("GRC"), at which point revenue requirements have already been determined, and settlements are the dominant method of resolving marginal cost, customer class revenue allocation, and rate design issues. This treatment is in contrast to generation (i.e., fossil fuel) resources, which are intentionally procured through RA and Long-term Procurement Proceedings, and generally passed through to revenue requirements in GRCs.

Progress has been made in readying supply resource DR to receive RA credits, and thereby be procured more akin to generation, which should advance further in this proceeding through adoption of an auction mechanism. Commensurate treatment should similarly be developed to secure load modifying DR.

Tracking DR Programs. The table below describes in which bifurcated category each current DR program could be located – supply or load modifying – as informed by program features. Though a number of programs are noted as "supply," characteristics and triggers may need to be modified to address flexible capacity needs and to enable CAISO to call on it as often as needed, for it to participate in the market. For these reasons, this process may take some time and should begin with programs best suited for transition and adjustment. Additionally, a number of programs could provide both distribution and flexible – particularly Category 1 – capacity benefits if they were geographically targeted. The chart below serves as a process step, identifying programs that appear better suited than others for entry into an auction mechanism.

DR Program Categorization

Utility	**DR Program**	**DR Category**	**Potential Action**
PG&E	SMART RATE RESIDENTIAL: Voluntary residential dynamic pricing plan.	Load Modifying	IOUs should maintain management of this program, altering and expanding it as needed.
PG&E	SMART AC: Air conditioner direct load control program. Separate programs are offered residential and non-residential customers.	Supply	This program should be combined with energy efficiency outreach, and emphasized for low-income households and small businesses. IOUs should maintain management of this program, post-auction, and receive RA credits if synced with CAISO needs.
PG&E SDG&E SCE	TIME-OF-USE RESIDENTIAL	Load modifying	More options should be provided, including geographically-targeted, marginal-cost-based, time-variant tariffs.
PG&E SDG&E SCE	BASE INTERRUPTIBLE PROGRAM: Tariff-based, emergency DR, dispatched based on CAISO system warnings and other emergencies related to the transmission or distribution systems.	Supply	This program could potentially be sub-aggregated so that different populations serve CAISO and IOU needs; and geographically targeted to maximize distribution, transmission, and generation benefits.
PG&E SDG&E SCE	CAPACITY BIDDING PROGRAM: Tariff-based aggregator managed demand response program that contracts directly with non-residential customers.	Supply	Appears transferrable to auction mechanism.
PG&E SDG&E SCE	DEMAND BIDDING PROGRAM: Available to time-of-use customers with maximum demands of 200 kW or higher who commit to reduce load by a minimum of 50 kW in each hour for two consecutive hours during a DBP event.	Supply	Appears transferrable to auction mechanism. Consider eliminating the maximum demand threshold for participant eligibility.

PG&E SDG&E SCE	PEAK DAY PRICING: Critical peak pricing (CPP) rate in which a higher price is charged for consumption of electricity during peak hours on selected days.	Load Modifying	Potential adder to a variety of tariffs.
PG&E SCE	AGGREGATOR MANAGED PORTFOILO: Nontariff based aggregator managed DR program that operates with Day-Ahead and Day-Of options.	Supply	Appears transferrable to auction mechanism.
PG&E SDG&E	PERMANENT LOAD SHIFTING PROGRAM: Provides a one-time incentive payment to customers who install qualifying PLS technology on chilled water cooling units (which differ substantially from typical central air conditioning units).	Load Modifying	Should be targeted geographically and temporally.
PG&E SDG&E SCE	TIME-OF-USE NON-RESIDENTIAL	Load modifying	More options should be provided, including geographically-targeted, marginal-cost-based, time-variant tariffs.
SDG&E	SMALL CUSTOMER TECHNOLOGY DEPLOYMENT PROGRAM: Provides enabling technology to residential customers at no cost in order to automate load reduction on demand response event days.	Supply and Load Modifying	Should be emphasized for low-income households.
SDG&E	PEAK TIME REBATE: Offers bill credits for reduced energy use between 11 a.m. and 6 p.m. on PTR event days.	Load Modifying	
SDG&E	SUMMER SAVER: Demand response resource based on central air conditioning (CAC) load control, available to both residential and nonresidential customers	Supply/ Load modifying	Could be used both on the load modifying and supply side, depending on how it's structured.
SCE	AGRICULTURE AND PUMPING INTERRUPTIBLE PROGRAM: Provides a monthly credit to eligible agricultural and pumping	Supply	Appears transferrable to auction mechanism.

	customers for allowing SCE to temporarily interrupt electric service to their pumping equipment during CAISO or other system emergencies.		
SCE	SUMMER DISCOUNT PLAN – COMMERCIAL: CAC direct load control program for commercial customers. During high system peak hours or emergency conditions, a signal is sent to control devices that limit the operation of the compressor in the CAC unit.	Supply	Appears transferrable to auction mechanism.
SCE	SUMMER DISCOUNT PLAN – RESIDENTIAL: CAC direct load control program for residential customers.	Supply	Appears transferrable to auction mechanism.
SCE	DEMAND RESPONSE CONTRACTS: Individually negotiated, and span a longer period of time over which load reduction resources ramp up to contractual levels. Aggregators contract with commercial and industrial customers to act on their behalf. Each aggregator forms a portfolio of customer accounts so that their aggregated load participates in the DR programs and penalty risk is mitigated.	Supply	Appears transferrable to auction mechanism.
SCE	SAVE POWER DAY: A peak time rebate program for residential customers. Customers on the program receive a rebate for reducing load during peak periods when events are called.	Supply	Management should be retained by utilities, post-auction, and receive RA credit if synced with CAISO needs.
SCE	REAL TIME PRICING: Dynamic pricing tariff that charges participants for the electricity they consume based on hourly prices that vary according to day type and	Load modifying	Should qualify for RA credits if addresses CAISO needs, particularly related to Category 1.

	temperature. It attempts to incorporate time-varying components of energy costs and generation capacity costs. Available to large commercial and industrial customers.		

b. Resource Adequacy Concerns

A resource that addresses capacity needs provides value to the system. The resource owner should, in turn, recoup this value, whether through RA credits or some other mechanism. Although progress has been made to allow supply side DR to more easily qualify for RA credits, more work needs to be done, including through the construction of an effective auction mechanism. Likewise, load modifying DR, which as discussed above could play a beneficial role in addressing the largest portion of ramping needs, should qualify for RA credits or a commensurate value stream. Without providing some revenue to the resource owner, valuable DR assets will neither be developed nor deployed. Determining how such value is to be provided is an essential part of unlocking the benefits DR can and should provide.

A variety of methods could be used to create incentives to activate load modifying DR. For example, RA credits based on performance could be offered to load modifying DR that reduces the need for flexible capacity. Likewise, the Commission could create a more dynamic process by which tariffs are developed and deployed, the structures of which would serve to induce ratepayer and third party DR engagement.

For example, PG&E's SmartAC Cycling DR program can be called at the substation level for distribution management purposes. PG&E currently has 31 substation-specific load control groups for the SmartAC cycling program, capable of providing 92 MW under 1-in-2 weather conditions on during July peak load.[38] To the extent that this and similar programs are triggered to address coincident peaks on the distribution system, which overlap with system-wide needs, they should be provided with RA credits.[39] That is, DR resources that are utilized to mitigate the need for distribution substation capacity expansion projects should be crafted to also create system benefits, and thereby be eligible for RA credits.

c. Supply Resource Issues

To effectively activate supply resource DR, a number of administrative barriers need to be removed. In particular, IOUs and third parties will need both the necessary tools and information flows to manage the relationship between supply side programs oriented to CAISO markets and the potentially impacted utility transmission and distribution systems. This need could be addressed through a series of improvements, including increased information-sharing and targeting DR to geographic locations in which it would provide the most benefit.

Supply Resource DR Use and Structure. As discussed in the previous section, DR load goals should be based on CEC's and CAISO's fully vetted forecasts of the need for different categories of flexible capacity, which reflect the shifts prompted by load modifying DR, as principally determined in the RA proceeding.[40] In respect to supply resource DR, this determination will in turn signal the level and characteristics of the resource needed. Its availability can then be encouraged to evolve, motivated principally by an auction mechanism

[38] California Public Utilities Commission, R. 13-09-011, *Pacific Gas and Electric Company (U 39 E) Compliance Filing Pursuant to Load Impact Protocol Filing Requirements:* Pacific Gas and Electric Company, *Executive Summary: 2014-2024 Demand Response Portfolio of Pacific Gas and Electric Company*, Appendix B (OIR) (April 1, 2014), https://www.pge.com/regulation/DemandReponseOIR-2013/Other-Docs/PGE/2014/DemandResponseOIR-2013_Other-Doc_PGE_20140401_300583.pdf

[39] The New Zealand utility Orion has employed mandatory coincident peak pricing distribution rates since 1990. Roughly half of Orion's distribution costs are allocated to the system's top 80 hours per year, resulting in very high costs during these hours. Customers are given 15 minutes before a pricing signal is communicated, and have equipment that can be automatically controlled. As a result of this tariff, Orion's load factor improved from 50 to 60 percent. Lynn Fryer, *et al., Demand Responsive Load Management: From Programs to a Demand Response Market*, Utility Issues, 5.105, aceee.org/files/proceedings/2002/data/papers/SS02_Panel5_Paper09.pdf.

[40] Note that this issue can be partially determined through Long-Term Procurement Proceedings as well.

that is open to a variety of third party DR providers and that offers sufficient funding for innovative and effective programs, such as automated DR.

Contract durations should generally match with the procedural schedule in which the program is identified as needed, though estimated minimum requirements could serve as the basis for longer-term commitments. For example, as described in the goals section, CAISO estimates that 400 to 3,500 MW of peak flexible load will be needed in 2015, depending on the month.[41] Offering longer-term contracts – to be renewed every other RA or procurement proceeding – for the low end of required MWs, with additional needs contracted for a single proceeding period, could support the evolution of DR programs.

Said differently, contract durations should be synced with procedural periods; with minimum levels of procurement authorized to extend over multiple dockets. This approach would provide demand response providers with longer-term contract assurances, enabling them to secure the necessary financing and investment to deliver the proffered megawatts; nest contracts within the established decision making processes, so as to avoid ad hoc extensions; and provide the Commission with the flexibility it needs to alter procurement amounts and types, particularly as load-shapes change over time.

<u>Supply Resource DR Forecasting.</u> CAISO, the IOUs, and the CEC should continue to make improvements in their forecasting methods. On the demand side, the IOUs and CEC should fully and expeditiously incorporate the influence of DR into their forecasts. This could be done by reflecting demand-elasticities in forecast models, based both on robust research results and changes observed in actual customer classes active in the market.

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[41] California Independent System Operator Corporation Submission of Preliminary 2014 Flexible Capacity Needs Assessment, R. 11-10-023, at 7, 9 (filed April 1, 2014), http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M090/K098/90098962.PDF.

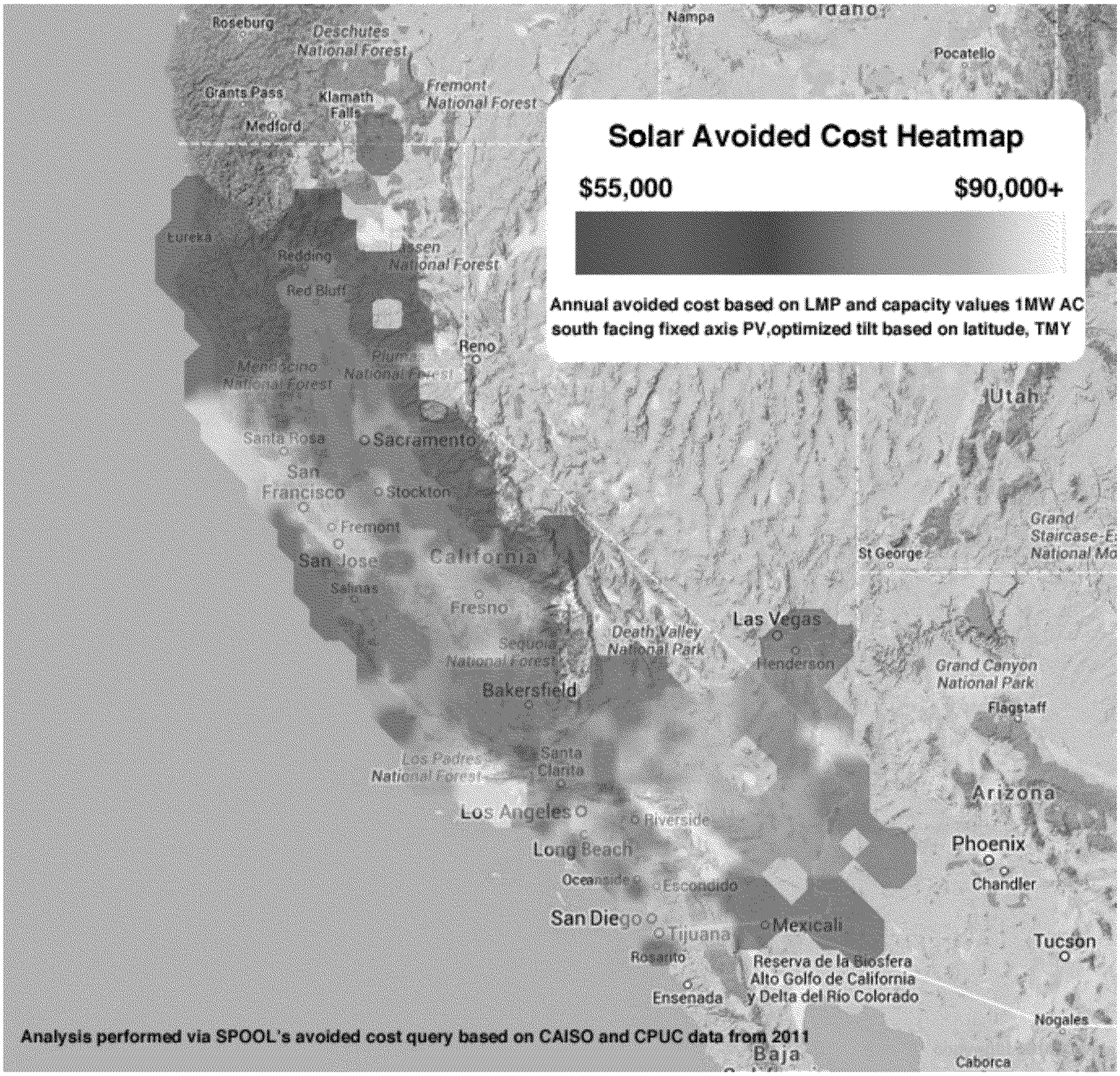
In addition, demand side forecasts should be available at the distribution planning level, and reconciled with area-based utility forecasts that are used to inform investments. This approach would provide for a check on the traditional top-down forecasting method – system wide forecasts can be reconciled with the combined total of geographic forecasts – as well as reinforce the basis for load modifying tariffs that incorporate benefits to the distribution system, as further discussed below.[42]

On the supply side, CAISO should continue to hone its estimates of flexible capacity needs, including by developing better data on the types of installed solar (e.g., tracking versus fixed); whether or not renewable resources are associated with "firming" DR or technology; and the balancing impact of resources located outside California.

d. Load Modifying Resource Issues

Load Modifying DR Forecasting. Voluntary time-variant rates that reflect geographic differences in service costs, and that are synced, to the extent possible, to coincident peaks would provide the opportunity to create the most value for IOUs and their customers. For example, in PG&E's service territory, marginal distribution capacity costs are five times higher on the Central Coast as compared to the North Bay. A graphic developed using SPOOL likewise reveals the significant variability in service costs. The map, as shown below, uses the total resource cost test to estimate the extent to which utility costs would be avoided by installing a 1 MW solar PV system at any given point.

[42] The value of geographically-targeted planning has been recognized by the State Legislature, albeit in a different context. AB 327 requires IOUs to "submit to the commission a distribution resources plan proposal to identify optimal locations for the deployment of distributed resources." These plans must "evaluate locational benefits and costs of distributed resources located on the distribution system…based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers." Section 769.



These examples illustrate the substantial potential benefit that could be unlocked with greater geographic granularity. Just as time-variant tariffs and programs that are offered uniformly throughout a utility service territory provide substantial benefits, geographically-targeted variant rates and programs can, present ratepayers with an even greater opportunity to play an active role in the electricity grid. For example, a voluntary time variant tariff that transparently indicated electricity use at a given time and place would provide third parties and ratepayers with motivation to market and adopt related enabling devices, thereby reducing the need for the largest tranche of flexible capacity (i.e., Category 1). Geographic-specific time variant rates that are based on marginal (i.e., forward-looking) costs would reflect the expense associated with forecasted demands, and as a result create a better market for load modifying programs to meet these needs.

As a step along this path, the CPUC could examine geographic cost differences, by, for example, ordering the IOUs to submit relevant data as part of DR tariff and program applications.[43] Adding to the information already collected as part of GRCs, a more granular approach in respect to all energy needs on the system would help in determining what types of resources would be most beneficially deployed in which areas of the state.

<u>Load Modifying DR as a System Resource.</u> Load modifying DR, if used appropriately, can provide extensive value to the grid. More than 90 percent of residential customer class revenues are collected through the E-1 Rate, a non-TOU rate which is offered to separately metered single-family dwellings, flats, apartments and farm houses, and corresponds to electricity demand at one of the steepest ramping periods.[44] Load modifying DR holds the potential to shift this use, though, for example, a time-variant rate like that proposed by SDG&E,

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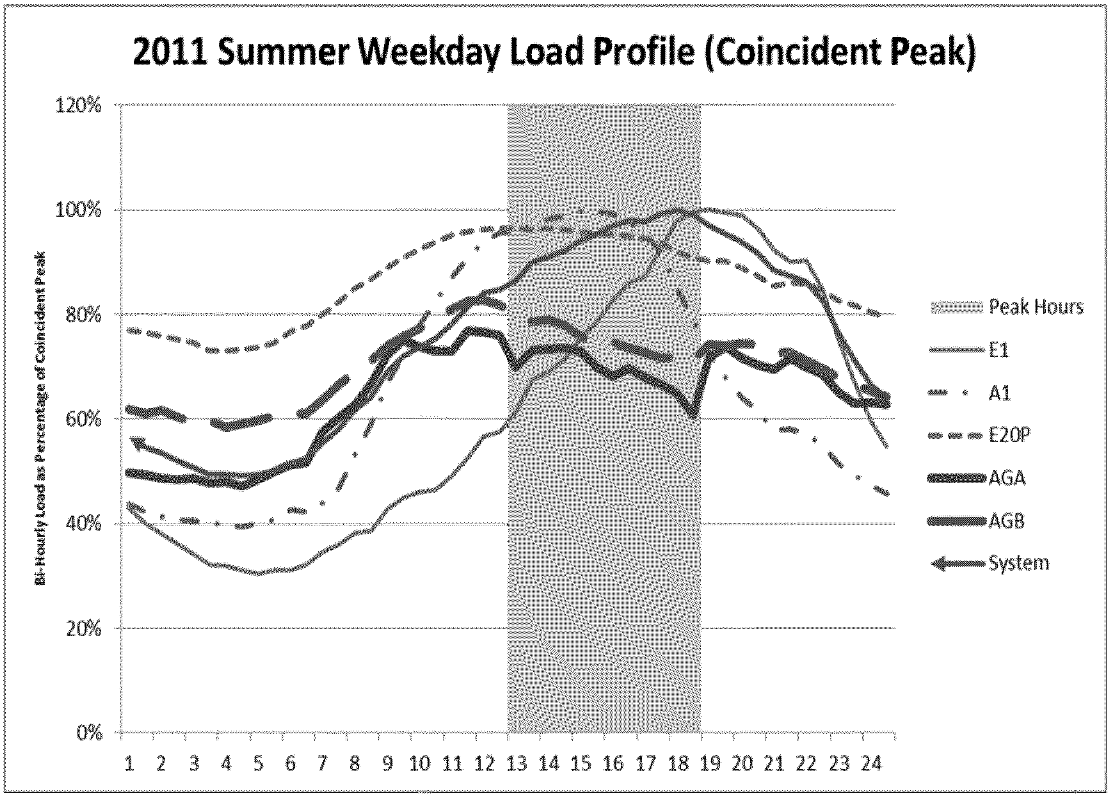
[43] EDF attempted to compile this information through data requests and other vehicles, but was not able to fully complete this effort before testimony was due.

[44] California Public Utilities Commission, A. 13-04-012, *Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design: Prepared Direct Testimony of Richard McCann, Ph.D. on Marginal Costs, Revenue Allocation, and Rate Design Issues on Behalf of the Agricultural Energy Consumers Association* (Application) (December 13, 2013), https://www.pge.com/regulation/GRC2014-Ph-II/Testimony/AECA/2013/GRC2014-Ph-II_Test_AECA_20131213_292891.pdf

and could significantly reduce the steepness of residential electricity demand ramps, which is shown in the figure below.[45]



Greater access to geographically targeted DR tariffs and programs represents the logical next evolutionary step in creating benefits and productive load shifts that address both distribution and system reliability needs. The IOUs already geographically target some of their DR programs, but not in a global manner that is coordinated with system flexible capacity needs.

For example, PG&E is deploying its Thermal Permanent Load Shifting program in specific areas to shift load from peak to off-peak periods as a means to mitigate the need for substation capacity expansions in the targeted areas, with the peak and off-peak periods

[45] California Public Utilities Commission, A. 13-04-012, *Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation, and Rate Design: Prepared Direct Testimony of Richard McCann, Ph.D. on Marginal Costs, Revenue Allocation, and Rate Design Issues on Behalf of the Agricultural Energy Consumers Association* (Application) (December 13, 2013), https://www.pge.com/regulation/GRC2014-Ph-II/Testimony/AECA/2013/GRC2014-Ph-II_Test_AECA_20131213_292891.pdf

determined at the substation, bank, or feeder level. The intent of this program is to reduce customer demand on targeted feeders or banks as a means to delay upgrading the facility to larger, more expensive, equipment.

SDG&E is proposing a similar tactic, by offering wholesale real time prices as part of an EV tariff that reflect congestion and other factors; and rates that signal the long term value of avoiding transmission and distribution upgrades as part of their VGI pilot. This pilot proposal contains three particularly important advancements, all of which correspond to needs identified in this Testimony. First, the pilot is responsive to geographic needs, providing "price signals that are intended to minimize [EV] charging impacts to SDG&E's system and local distribution capacity."[46] Second, the pilot proposes technology-based solutions, including phone-based apps to empower EV customers to conveniently minimize their charging costs, including charging their cars when energy prices are low. Third, the pilot contains a tariff design that will include price attributes made up of:

1. a variable commodity component based on CAISO day-ahead hourly price;
2. a dynamic pricing signal via a tariff mechanism (similar to SDG&E's CPP-D tariff) for the recovery of commodity capacity costs; and
3. a dynamic pricing signal (also similar to SDG&E's CPP-D tariff), designed to recover distribution circuit peak costs and address local capacity concerns.[47]

[46] Application of San Diego Gas & Electric Company (U 902 E) for Approval of its Electric Vehicle-Grid Integration Pilot Program, Prepared Direct Testimony of Cynthia Fang, Chapter 3, on Behalf of San Diego Gas & Electric Company, A.14-04-014 (filed April 11, 2014), at CF-1, https://www.sdge.com/sites/default/files/regulatory/Chapter_3_Fang_Testimony_VGI.pdf.

[47] *See id.*, *See* Application of San Diego Gas & Electric Company (U 902 E) for Approval of its Electric Vehicle-Grid Integration Pilot Program, A.14-04-014 (filed April 11, 2014), https://www.sdge.com/sites/default/files/regulatory/VGI%20Application_FINAL.pdf; *See* Application of San Diego Gas & Electric Company (U 902 E) for Approval of its Electric Vehicle-Grid Integration Pilot Program, Prepared Direct Testimony of Lee Krevat, Chapter 1, on Behalf of San Diego Gas & Electric Company, A.14-04-014 (filed April 11, 2014), https://www.sdge.com/sites/default/files/regulatory/Chapter_1_Krevat_Testimony_VGI.pdf.

This pilot thus presents an opportunity to provide precise price information to customers in ways that reduces costs across the grid. Fundamentally, the VGI pilot proposal also points to ways EVs can provide a valuable DR resource that is informed, in part, by distribution level costs. These types of opportunities, if implemented systematically, would reduce both distribution costs and address Category 1 flexibility needs if calibrated to shift coincident peaks.[48]

Likewise, SCE's Preferred Resource "Living" Pilot will "procure and evaluate the ability of Preferred Resources to meet Local Capacity Requirements ("LCR")."[49] The pilot's purpose is geographic specific, to

> …help inform electric system operators, transmission planners, and procurement entities about the ability and availability of Preferred Resources to perform where and when needed to meet local reliability, while ensuring grid stability and resiliency.[50]

The research endeavors to demonstrate the extent to which time-variant tariffs can be relied upon and planned for to augment other resources in the pilot study area. This, in turn, can help reveal how tariffs can be used to avoid capacity upgrades. Within this one pilot area alone, EDF estimates that there is a potential to reduce peak load by approximately 80 MW, roughly equivalent to a larger peaker power plant, if 50% of residential customers adopt the existing TOU-D1 rate and engage in load shifting akin to what has been observed repeatedly in statistically valid studies.

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[48] The congruence between local and system peaks is significantly influenced by the type of customers served at the local level. For example, a substation dominated by residential customers will have a different load shape than one catering predominately to agricultural customers. This characteristic lends itself to offering tailored DR programs and tariffs.

[49] Notice sent to service list in R.12-03-014, *available at* https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCsQFjAA&url=https%3A%2F%2Fwww.pge.com%2Fregulation%2FDemandResponseOIR%2FCPUC Docs%2FCPUC%2F2013%2FDemandResponseOIR_Doc_CPUC_20130926_287234.doc&ei=NAxpU4TdLa7jsAS9woLoAw&usg=AFQjCNF8T8RtyFYTG9Pi-zrFL9qCIrfHnQ&sig2=HTehbOK4js9eSkmhTZeQEg&bvm=bv.66111022,d.cWc&cad=rja

[50] *Id.* at 1.

Load Modifying DR Value Stream. As stated earlier, load modifying DR should be treated commensurately to supply resource DR. This treatment should extend to how value streams are structured. In terms of "contract assurance," load modifying DR should be understood as agreements with ratepayers – as well as third party providers – with established term periods. Viewed through this lens, energy users and technology vendors should be provided with the certainty they need to make investments that are predicated on a particular rate structure.

Securing load reductions achieved through load modifying DR should be appropriately motivated. For example, RA credits could be used with the DR, RWD, and GRC proceedings staged so that resulting RA-worthy DR is credited in the appropriate RA proceeding. Utilities and third parties that provide the relevant service would then be able to receive RA credits and/or otherwise recover the value they are providing to the system.

In respect to the IOUs, rate basing appropriate DR tariffs and programs, in a way similar to new generation capacity, provides another possible avenue for compensation. First, the utility would need to determine the need for load relief at a specific distribution node, and demonstrate to the CPUC that deployment of the proposed DR measure would be more cost-effective than alternatives, in which case the asset would be eligible to be rate based in a similar, though discounted, fashion as the otherwise "hard" investment that would have had to be made. Second, if intervention would additionally reduce or fulfill the need for flexible capacity, as identified by CAISO, it would be eligible for RA credit (the value of which, in turn, could be included in the cost-effectiveness analysis). Third, load impact data would be provided as part of CEC and CAISO forecast processes, so that resulting load shifts are properly represented. In addition, to the extent that DR programs are built from the distribution level up, utilities should be able to rate base associated investments, and be compensated for their administrative, outreach and educational efforts that support enrollment and response.

e. Demand Response Auction Mechanism

If successful, the Demand Response Auction Mechanism ("DRAM") will effectively induce additional supply-side DR into a more active marketplace. According to the Brattle Group:

> California may actually be under-procuring low-cost DR by effectively precluding third-party DR suppliers from accessing capacity payments. By allowing third-party curtailment service providers (CSPs) to monetize the value of peak load reductions without going through LSEs, eastern U.S. power markets such as PJM observed rapid growth in low-cost DR, sufficient to cover 10% of the system's peak load for 2015-16. These third-party DR resources have taken on resource adequacy commitments at capacity prices far below the cost of new generation and the "capacity value" assumed in California's DR cost-effectiveness tests.[51]

However, significant design issues must be addressed to create an efficient and equitable auction mechanism, with sufficient time and adaptive "learning by doing" to fully and effectively draw in and deploy cost-effective resources. Existing financial and institutional barriers should inform the Commission's decisions regarding which types of DR should be bid into the DRAM. Although a DR auction could ultimately be able could accommodate a wide variety of DR, practical reasons, including the transaction costs of handling millions of small exchanges, particularly those with uncertainties associated with them, suggest that an evolving floor should be set. This floor could be based, as an example, on the size of a DR resource, in terms of the amount of contiguous minutes it is available, for how many total MW-hours. In such a scenario, a minimum MW of dispatchable load, such as three MW, would be required to

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[51] Johannes P. Pfeifenberger, *et al., Resource Adequacy in California: Options for Improving Efficiency and Effectiveness*, The Brattle Group (October 2012), http://brattle.com/system/publications/pdfs/000/004/827 /original/Resource_Adequacy_in_Califonia_Calpine_Pfeifenberger_Spees_Newell_Oct_2012.pdf?1378772133.

be available for a minimum amount of time, such as one hour. Lesser amounts could additionally be eligible if bundled together on the same node to meet a minimum obligation.

As previously discussed, given the value DR can simultaneously provide to the distribution system – as well as the need for the IOUs to know of possible DR impacts on their wires – the auction bidding process should include identification of the geographic location of curtailable load that is accessible to the IOUs. This would represent an extension of existing DR aggregation, dispatch, and associated mapping efforts at the sub-Load Aggregation Point level. This information could be leveraged to could provide additional system benefits. For example, if IOUs identified emerging nodes of coincident peak congestion on their distribution systems, as part of the auction process supply resource DR focused on these nodes could be more accurately (and more highly) valued.

IV Conclusion

DR can substantially contribute to creating a lower impact grid, both in terms of economics and the environment. The time is ripe for the Commission to take the necessary steps, as outlined in this testimony, to engender the right conditions for load modifying resource DR to play its proper role in managing flexible capacity needs; and for supply resource DR to cost-effectively and sustainably address residual flexible capacity requirements.

This concludes the Testimony of Steven Moss.

Respectfully signed and submitted on May 6, 2014

On behalf of Environmental Defense Fund,

Witness:

/s/ Steven Moss

Partner
M.Cubed
2325 Third Street, Suite 344
San Francisco, California 94114
Phone: 415-643-9578
Email: steven@moss.net

Party on Record:

/s/ Michael Panfil

Michael Panfil
Attorney
Environmental Defense Fund
1875 Connecticut Ave., NW
Washington, DC 20009
Phone: (202) 572-3280
Email: mpanfil@edf.org

ATTACHMENTA

STEVEN J. MOSS

PROFESSIONAL EXPERIENCE

Mr. Moss has participated in multiple initiatives focusing on a variety of energy and water issues. He has led efforts to reduce electricity costs, and provide better pricing options, on behalf of agricultural, commercial, and residential ratepayers; estimated the economic benefits associated with investments in energy-related research and development; examined the environmental impacts associated with various uses of energy, including in transportation. He is currently examining whether a small hydroelectric facility in Northern California is needed for reliability purposes; analyzing ways to better manage agricultural energy use during a period of water scarcity in California Central Valley; and contributing to efforts to develop renewable energy in East Africa.

REPRESENTATIVE CLIENTS

Agricultural Energy Consumers Association, American Farmland Trust, Bank of America, California Air Resources Board, California Energy Commission, California Farm Bureau Federation, California Public Utilities Commission, California Truckers Association, Consulting Engineers and Licensed Surveyors of California, Environmental Defense Fund, Los Angeles County Sanitation Districts, Natural Gas Vehicle Coalition, Rail Watch, Reason Foundation, Redefining Progress, Southern California Gas Company, Western Manufactured Home Parks Association, Western States Petroleum Association.

ACADEMIC ACHIEVEMENTS

- Fulbright Indo-American Environmental Leader Fellowship, 2004.
- Salzburg Seminar Fellow, 2001.
- Kellogg National Leadership Fellow, 1997-2000.
- Presidential Management Intern, 1985 – 1987.
- Masters of Science, Public Policy, University of Michigan, Ann Arbor, 1985.
- Bachelors of Science, Conservation of Natural Resources, University of California, Berkeley, 1982.
- Lyndon B. Johnson Congressional Scholar, 1981.

PROFESSIONAL EMPLOYMENT AND DEVELOPMENT

- Budget Advisor, Office of Technical Assistance, U.S. Treasury Department, 2006-2010.
- Publisher, *Potrero View*, 2006-present.
- Supervisor's Appointee, Potrero Power Plant Citizen's Task Force, 2001-2010.
- Executive Director, San Francisco Community Power, 2001-Present.
- Governor's Appointee, California Inspection and Maintenance (Smog Check II) Review Committee, 1997 - 2001.
- Partner, M.Cubed, 1993 – Present.
- Senior Economist, Foster Associates, 1987-1993.

- Adjunct Lecturer in Environmental Economics, California History, Public Policy Analysis, Golden State University, San Francisco State University, San Quentin State Prison, 1997 - 2006.
- Congressional Staff, U.S. House of Representatives, 1987.
- Budget Examiner, U.S. Office of Management and Budget, 1985 - 1987.

REPRESENTATIVE PUBLICATIONS

Left to Our Own Devices, Financing Efficiency for Small Businesses and Low Income Families, for Environmental Defense Fund, December, 2009; *Market Segmentation and Energy Efficiency Program Design,* for CIEE, November 2008; *Distributed Energy Resource Implementation: Testing Effective Load Management at the Feeder Level, Draft Interim Report*, published by the California Energy Commission, Winter, 2007; *Statewide Pricing Pilot: Track B Evaluation of Community-Based Information Treatment*, published by California Public Utilities Commission, Fall, 2005; "Community-Based Trading Mechanisms to Reduce Polluting Air Emissions and Address Global Warming," *Journal of Environmental Assessment, Policy, and Management*, June 1999; "The Use of Demographic and Economic Forecasts in Air Quality Policymaking," *Environmental Regulation and Permitting*, Spring 1998; *Economic Analysis of the Proposed 1994 State Implementation Plan Conducted Prior to its Consideration by the California Air Resources Board*, published by the Cal-EPA February 1996.

SELECTED PROJECTS

Distributed Energy Resources "Test Bed" Project, California Energy Commission, (2004-2008). Examined DER's impact on two distribution feeder lines to determine benefits and costs from utility, ratepayer, and societal perspectives. Project included developing and implementing energy efficiency and demand-response programs and technologies targeted at small and medium commercial energy users.

Statewide Pricing Pilot, Track B Analysis, California Public Utilities Commission (2003-2005) Developed experimental program to examine whether providing educational "treatments" communicated through a community-based organization in an environmentally-impacted neighborhood enhanced responses to critical peak pricing among residential energy users. The project included survey and econometric research.

San Francisco Community Power, City and County of San Francisco (2001-present). Launched San Francisco Community Power in Southeast San Francisco. The organization's objectives included assisting small businesses and low income residences to better manage their energy use, thereby generating environmental and economic benefits; training community residents to install and distribute energy-saving measures; providing technical assistance on energy-related issues to community groups and policy makers; and producing high-quality news and information about environmental issues to San Francisco residents.