DOCKETED	
Docket Number:	25-IEPR-05
Project Title:	Load Shift Goal Update
TN #:	264606
Document Title:	Leapfrog Power Comments - IEPR Load Shift Goal Workshop [CORRECTED]
Description:	Correction on previous comment filing TN #: 264594
Filer:	System
Organization:	Leapfrog Power
Submitter Role:	Public
Submission Date:	7/10/2025 10:59:29 AM
Docketed Date:	7/9/2025

Comment Received From: Leapfrog Power
Submitted On: 7/10/2025
Docket Number: 25-IEPR-05

Leap Comments on IEPR Load Shift Goal Workshop [CORRECTED]

Additional submitted attachment is included below.

July 9, 2025

California Energy Commission
Docket Unit, MS-4
715 P Street
Sacramento, CA 95814

RE: Leap Comments on IEPR Commissioner Workshop on California's Progress Toward the Load-Shift Goal

The IEPR Commissioner Workshop on California's Load Shift Goal was a well-structured convening that surfaced a number of important observations about California's ongoing efforts to reach 7 GW of load shift potential across the state. However, one topic that did not receive enough attention was the dramatic reduction in supply-side demand response (DR) over the past few years. According to CEC's analysis, the amount of market-integrated DR that the state has access to dropped from 1,014 MW in 2022 to 558 MW in 2024, a dramatic reduction to what had previously been the state's largest load flexibility resource. A roughly 50% cut to supply-side DR is especially concerning because, unlike load-modifying DR, supply-side DR is integrated into California's RA program, providing CAISO with visibility into its contracted load reductions.

The CEC provided several potential explanations for this, including the loss of the Planning Reserve Margin (PRM) adder and sunsetting of the Demand Response Auction Mechanism (DRAM) program. However, none of these can fully explain this dramatic loss in demand reduction capacity. The PRM only added 9% to supply-side DR capacity values (or ~11% with the Transmission Loss Factor adder), and DRAM was not sunset until 2025. It is more likely that supply-side DR is shrinking due to the numerous regulatory barriers that the CEC identified in its review of its stakeholder surveys. Although the CEC did not explicitly make this connection, it cannot be ignored that challenges like restrictive program requirements, lack of standards, and poor data access are actively undermining California's effort to achieve its load shift goal.

Fortunately, the CEC's stakeholder survey turned up a number of potential solutions that could help reverse the plummeting supply-side DR capacity in its "Economic DR" category. Tom Flynn's presentation mentioned a number of promising options, including expanded use of device-level measurements, shorter dispatch durations, and a centralized data repository. Leap actually described these and several other solutions in a recent white paper it published on regulatory actions that California could take to advance supply-side DR and achieve its Load Shift Goal.

In addition to the solutions described above, this white paper identified regulatory changes that could improve DR performance measurement and better account for VPPs full capabilities as market participants. This included allowing DR to sell capacity across all 24 hours of the day, compensating VPPs for exports back to the grid, and implementing "prescriptive baselines" that would streamline DR performance measurement. The white paper goes into more detail about why these changes are important and which California regulatory agencies should take the lead in implementing them. I've attached it as an addendum to these comments to enter them into the record and provide a reference for the CEC and other stakeholders as they chart next steps.

I'd also like to highlight the suggestion for a centralized data repository as one that would be particularly valuable to consider. Currently, customers must go through their utility's Share My Data (SMD) authorization page to enroll in a supply-side DR program with a third party, which typically requires them to authenticate their identity with their utility log-in information or account number. These credentials are not always readily on hand, and in Leap's experience, less than 50% of customers that begin this SMD process actually complete it. Creating a centralized data repository that customers can access with more modernized authentication procedures would radically increase the ease with which customers can enroll in supply-side DR, allowing many smart device owners who are currently sitting on the sidelines to participate in these programs.

This is not a niche position. The suggestion to create a centralized data repository has come up in a number of other regulatory venues, including the CPUC's High DER proceeding (R.21-06-017) and the Data Working Group under its Customer DR proceeding (D.22-11-013). In a recent filing with the CPUC, PG&E agreed that California's Share My Data authorization process makes DR enrollment more onerous, and it explicitly called out the fact that its Automated Response Technology (ART) program avoids this process as a reason why ART is less complex for customers.[1] In addition, as the presentations during the workshop made clear, it has been

[1] See: "Pacific Gas and Electric Company's Reply to the Protest from Leapfrog Power, Inc. to Advice 7577-E – PG&E Advice Letter to Update Eligible Demand Response Program Lists to Include the Automated Response Technology Program, in Compliance with D.23-12-005 and D.24-03-071."

implemented in several other U.S. states and countries to address data access issues, with substantial success.

In its white paper, Leap identified the CEC as an appropriate agency to host this centralized data repository in California, given the agency's experience managing historic meter data from customers across California. In the Workshop, Commissioner J. Andrew McAllister provided an update on this "retrospective" data repository, stating that it currently receives data from utilities roughly once a quarter and is "well-positioned" to take the next step. He noted that receiving this data more frequently would have a lot of value, and that there should be a conversation on whether the CEC should enhance its data repository to serve additional functions.

Leap agrees, and it encourages California's regulatory agencies to create additional platforms to discuss and refine this and other solutions. Per the California Energy Efficiency + Demand Management Council's suggestion, one helpful step would be for the CPUC to open a rulemaking specifically focused on demand response. This would provide a venue to continue the conversation on a centralized data repository and other regulatory actions that could address the obstacles to supply-side DR participation in California, stemming further reductions in demand flexibility and allowing the state to fully leverage these resources to support its grid.

Respectful submitted,

Collin Smith

Collin Smith
Regulatory Affairs Manager
Leapfrog Power (Leap)
collin@leap.energy

WHITE PAPER

The Road to Seven Gigawatts: Concrete Steps to Unlock California's Demand Response Potential

February 2025

Executive Summary

California is at a crossroads. Electricity prices in the state are soaring, and growing peak load from electrification will continue to push up costs for customers. Virtual power plants (VPPs) offer a cost-effective way to manage this peak load, but there's a gap between the resources that California has access to and what it's currently using.

This paper identifies key challenges hindering the growth of California's VPP market and proposes targeted regulatory and market reforms to unlock demand-side flexibility at scale. Specifically, it outlines three critical areas where state policymakers must act:

I. Disintermediate Customer Data Access

VPPs require seamless, equitable access to customer energy data, yet the current system forces third-party demand response providers (DRPs) to rely on utility-controlled platforms that are inefficient and unreliable.

Key recommendations:

1. Establish a Statewide Data Access Platform

2. Utilize Device-Level Measurements

II. Adjust Wholesale Markets to Fully Account for VPP Capabilities

Existing market rules prevent distributed energy resources (DERs) from receiving full compensation for the value they can provide to the grid.

Key recommendations:

1. Compensate VPPs for Grid Exports

2. Allow VPPs to Sell Capacity in All Hours of the Day

3. Establish Shorter Dispatch Durations

III. Update Methodologies to Forecast and Measure VPP Participation

Current forecasting and baseline methodologies impose excessive burdens on DRPs, leading to market inefficiencies and underutilized capacity.

Key recommendations:

1. Provide More Flexibility for Demand Response (DR) Resource Forecasts

2. Implement Prescriptive Baselines

To implement these changes, California's key energy regulators - the **California Independent System Operator (CAISO),** the **California Public Utilities Commission (CPUC),** and the **California Energy Commission** (**CEC)** - must take coordinated action. The table below gives a more comprehensive summary on what each agency can do to make progress on the identified reforms:

	Disintermediate Customer Data Access	Adjust Wholesale Markets to Fully Account for VPP Capabilities	Update Methodologies to Forecast and Measure VPP Participation
CAISO	Develop rules and standards to accept device-level data outside of utilities' data authorization processes.	Implement a new mechanism to compensate DERs for grid exports.	Move baseline rules to Business Practice Manual and develop prescriptive baseline option(s).
CPUC	Authorize development of a statewide data access platform to host utility data. Create standards for the frequency and accuracy with which utilities share data with new platform.	Evaluate and assign net qualifying capacity for VPPs across all 24 hours of the day. Allow DR resources to dispatch for shorter durations (e.g. 1-2 hours).	
CEC	Manage and host a statewide data access platform for both utility and device-level energy load data.		Develop prescriptive baselines for different customer and technology types using historic customer data.

By addressing these regulatory gaps, California can unlock the full potential of VPPs, delivering a more cost-effective, flexible, and reliable energy system. The state has set ambitious goals for demand-side flexibility, but achieving them requires bold policy action. The recommendations in this paper provide a clear roadmap to ensure VPPs can scale and support California's clean energy future.

Introduction

As California's energy market continues to evolve, demand-side energy solutions are becoming increasingly important tools for enhancing grid reliability. Aggregations of distributed energy resources (DERs) can provide flexible, targeted support to local grids in California when deployed as virtual power plants (VPPs). With rising electricity demand, constrained energy supply, and more frequent extreme heat events straining the grid, the need to scale demand-side solutions in California has never been more urgent.

Employing DERs to support the grid offers a cost-effective way to address capacity constraints and peak load growth in California. According to a 2023 report by the Brattle Group, VPPs constructed from grid-connected DERs can provide peak capacity at 40-60% less cost than utility-scale batteries or traditional gas generators.[1] The Brattle Group followed up this report with a California-focused analysis in 2024, finding that VPPs could supply 15% of the state's peak demand by 2035, saving ratepayers $50 million per year and returning an additional $500 million to electricity customers that participate in VPP programs.[2]

The rapid proliferation of DERs across California presents a significant opportunity for demand response (DR) and other grid services solutions to play a transformative role in energy management. However, much of that potential remains untapped: according to the Lawrence Berkeley National Laboratory, if the industry continues enrolling customers at the same rate as it did in 2019, by 2050 there will be only one-fifth as much DR enrolled as is economically feasible for California to deploy.[3]

The California Energy Commission (CEC) recognized this gap when it released its Load Shift Goal Report in 2023, which established a goal for California to reach 7 GW of demand flexibility by 2030. This goal was based on the CEC's assessment of statewide achievable potential for flexible demand resources, showing that California could roughly double its available demand flexibility compared to 2022. This goal was accompanied by a load flexibility framework and policy recommendations designed to accelerate DR program enrollments in California.[4]

The CEC's policy recommendations were a good start, but more concentrated regulatory action is needed to address the root causes of the problems it identified. This paper outlines targeted recommendations for California's energy regulators to implement crucial changes that will catalyze the state's VPP market, unlocking the full potential of demand-side energy solutions to support a cleaner, more reliable grid.

[1] Ryan Hledik and Katae Peters, "Real Reliability: The Value of Virtual Power," The Brattle Group, May 2023, p. 6. Available here.
[2] Ryan Hledik, Kate Peters, and Sophie Edelman, "California's Virtual Power Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability," The Brattle Group, April 2024, p. 6. Available here.
[3] Brian F. Gerke et al. "The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources Through 2050," Lawrence Berkeley National Laboratory, 21 May 2024, p. 122. Available here.
[4] California Energy Commission, "Senate Bill 846 Load-Shift Goal Report," May 2023.

Background: California's Demand Response Landscape

California has one of the more diverse and sophisticated DR markets in North America, but its breadth of participation opportunities is both a boon and a curse. It allows the state to run experiments on different participation methodologies to determine what works best, but it also creates significant complexity, as the number of programs available for VPPs has proliferated over time. This is especially true for new DER providers, such as automotive companies, who do not have the context or energy sector expertise to navigate the complex ecosystem of DR programs in California.

In its Load Shift Goal report, the CEC divided California's demand flexibility programs into several categories. This white paper is focused on two categories: Resource Planning and Procurement and Incremental & Emergency. These categories contain a wide range of programs and resource types, all of which are "VPPs" in the sense that they "dispatch" DR resources to address grid needs on a flexible basis, the same way a power plant would be dispatched to address high demand.

TABLE 1: California Demand Response Estimates vs Target[5]

Category	Sub-Category	2022 Estimate	2030 Goal
Resource Planning and Procurement	Economic Supply-Side DR	~750 MW	4,000 MW
	Reliability Supply-Side DR	740 MW	
	Public Utility DR Programs	210 MW	
Incremental & Emergency	I&E Programs	800 MW	
	Back-Up Generators	375 MW	
	Total	**~2,875 MW**	**4,000 MW**

Within this larger subset of VPP programs, the category of "Supply-Side DR" (SSDR) has the greatest potential to scale. These programs are bid directly into California's wholesale market, dispatched according to electricity costs, and funded through the Resource Adequacy (RA) payments that CAISO uses to finance most of the state's capacity. As a result, they have reliable, long-term financing streams that aren't available to programs funded via legislation or even utility rates, and they're subject to market forces that work to keep their costs low.

[5] California Energy Commission, "Senate Bill 846 Load-Shift Goal Report," May 2023, p. 4. The additional 3 GW of the CEC's 2030 Goal are expected to come from Load Modifying Demand Response (described in more detail below)

The two SSDR sub-categories identified in the Load Shift Goal report, Economic SSDR and Reliability SSDR, are already two of the largest types of VPPs that the CEC lists, but their contributions to California's grid are actually shrinking. Since 2022, the amount of "qualifying capacity" (QC) awarded to SSDR (i.e. the capacity available to grid operators from third-party DRPs) has actually fallen by 66%, moving California further away from its goal.[6]

However, a few targeted changes by state regulators could substantially increase the VPP capacity that the state has access to. By removing existing regulatory barriers, California could expand VPP participation and improve performance, helping to fully unlock the potential of these resources to support the grid.

TABLE 2: Load Modifying vs. Supply-Side Demand Response Programs:

Category	Load-Modifying DR (LMDR)	Supply-Side DR (SSDR)
Description	Programs that shift or reduce electricity demand but are not directly part of RA frameworks.	Programs that bid DR resources directly into California's wholesale market, operating within CAISO.
Participation	Not bid into wholesale markets; relies on customers responding to price signals or incentives.	DR providers contract with Load Serving Entities (LSEs) and bid capacity into CAISO markets.
Dispatch Method	Continuous or price-responsive; customers shift load in response to time-based rates.	Event-based; dispatched when electricity prices are high or in grid emergencies.
Primary Goal	Encourages everyday load shifting and efficiency to reduce peak demand over time.	Provides flexible, market-based capacity that can be dispatched when needed.
Example Programs	Time-of-Use (TOU) rates, energy efficiency programs.	Capacity Bidding Program, Demand Response Auction Mechanism (DRAM), third-party RA contracts.
Programs like the Emergency Load Reduction Program (ELRP) and Demand Side Grid Support (DSGS) program are similar to SSDR in that they're dispatched on an as-needed basis based on conditions on the grid. However, these resources are not bid directly into CAISO's market, and they are funded by (respectively) customer rates and legislative funds.		

[6] Based on a review of August Net Qualifying Capacity awards for third-party DRPs from 2022 to 2025. [Available here.]

Key Recommendations

I. Disintermediate Customer Data Access

VPPs cannot exist without access to customer energy data. Without knowledge of how customers are using energy, demand response providers (DRPs) cannot measure responses to DR events, making it impossible to know if the agreed-upon load reduction was actually delivered. Unfortunately, access to customer energy data is not evenly distributed. Almost all data used in DR programs today comes from customers' utility meters, making the utility the sole repository of customer energy data; third-party DRPs can only access this data if utilities share it with them.

Today, utilities provide DRPs with access to this data if a customer authorizes access via California's ShareMyData (SMD) platform. The need for authorization is wholly appropriate, since customers should have control over how their data is shared. However, because SMD is a utility platform, it makes the utility the de facto gatekeeper of the customers' data.

As a result, access to customer data has become a significant stumbling block for scaling DR in California. Over 50% of customers that begin the SMD process fail to complete it, stymied by requirements that they verify their identity with the utility by providing their utility log-in credentials – information that many customers do not have on hand.

Over 50% of customers that begin the ShareMyData process fail to complete it.

The SMD platform itself experiences frequent outages, which utilities have little incentive to fix because third-party DR programs do not provide them with additional revenue.

Even if data is successfully authorized, the flow of that data from utilities to third-party DRPs often experiences significant delays and corrections that make it challenging for DRPs to provide timely and accurate accounts of DR performance to both customers and the market. Oftentimes, due to delays in receiving customer data, a DRP cannot be sure of their performance in a DR event until months after the event was called.

This time lag makes it both difficult to have conversations with customers on how to improve their performance and to develop solutions to address underperformance in a timely manner.

Ultimately, customers should have the ability to share the data produced by devices they purchased without utility intervention.

Here we describe two potential pathways to effectively disintermediate customer data.

1. Establish a Statewide Data Access Platform

A logical evolution for data access would be shifting that data from utility servers to a neutral third-party platform. This platform would host utility-collected customer meter data and facilitate transactions for energy services by sharing that data to entities authorized by the customer. This role would be similar to other centralized entities set up to facilitate market transactions, such as the independent system operators (ISOs) that run wholesale electricity markets, and would likely be overseen by a governmental or quasi-governmental organization to ensure impartiality.

Since distribution utilities are regulated at the state level, this data access platform would probably also be established at the state level via the state's utility commission. By creating a single platform for utility-provided data, the state can also realize cost savings by avoiding having each utility build out separate platforms and protocols for data access, which may not provide a standardized method for customers to share their data.

A logical evolution for data access would be shifting that data from utility servers to a neutral third-party platform.

Many states and countries have already recognized the value of this idea and have set up (or are in the process of setting up) these types of centralized data access platforms:

[7] "Smart Meter Texas Residential User Guide," 26 February 2024, p. 3. [Available here.](#)

TABLE 3: Examples of State- and Country-Wide Data Access Platforms

State/ Country	Name	Description
Texas	Smart Meter Texas	Texas established the first iteration of its statewide data access platform, Smart Meter Texas, in 2010. Initially developed to facilitate customers' ability to choose between different retail electricity providers (REPs), the platform was developed by the state's five largest distribution utilities and overseen by the Public Utility Commission of Texas. Customers can log on to the platform to see their individual energy usage data, and can also share that data with authorized third parties.
New York	Integrated Energy Data Resource Program	New York is developing an Integrated Energy Data Resource (IEDR) to provide a single statewide platform to securely collect, integrate, analyze, and make accessible energy-related information from utilities. Types of data may include energy usage data, digitized tariff parameters, and network demand data. The New York State Energy Research and Development Authority (NYSERDA) is responsible for defining, initiating, overseeing, and facilitating the IEDR Program on behalf of New York.[8]
Denmark	Energy Data Service	In 2017, Denmark's national transmission operator, Energinet.dk, launched a platform to provide real-time access to Danish energy data.[9] The platform contains a third party access-solution in which consumers can grant secure access to their data to energy market participants authorized by Energinet.dk.[10]

[8] New York State Energy Research and Development Authority, "Integrated Energy Data Resource Program Consolidated Program Charter," August 2021. Available here.

[9] Open Knowledge Foundation, "Danish Energinet.dk will use CKAN to launch Energy DataStore – a free and open portal for sharing energy data," 20 January 2017. Available here.

[10] Energinet website. Available here.

2. Utilize Device-Level Measurements

Another option to disintermediate access to customer data is by looking beyond the utility meter as the sole source of that data. This is increasingly possible in today's energy landscape, as the Internet-connected devices participating in DR programs also have the ability to directly transmit data on their energy usage.

This is straightforward for devices like distributed batteries and electric vehicles (EVs), which have detailed data on the energy moving into (and out of) the battery. But it's also possible for smart thermostats and other household devices, which can convert operational data on when and how that device runs into a record of energy consumption.

Some programs in California, such as the Demand Side Grid Support (DSGS) program, allow for device-level measurements to be used to evaluate DR performance, a component that has contributed to the rapid growth in resources participating in the program.

CAISO also allows for device-level measurements for specific technologies (i.e. distributed batteries, EVs), but it still requires these customers to complete the utilities' SMD authorization. This prevents device-level measurements from streamlining the authorization process, which is one of the primary benefits that this approach provides in DSGS.

Device-level measurements could also be implemented in coordination with a statewide data access platform. In this case, the statewide platform would host both device-level and meter data, enabling customers to authorize the sharing of either source's data with the same authorization form.

The platform could also keep track of which programs each device is enrolled in, ensuring that devices are never enrolled in conflicting programs at the same time while still allowing multiple devices controlled by different DR aggregators to all provide their services to the grid.

II. Adjust Wholesale Markets to Fully Account for VPP Capabilities

VPPs have expanded dramatically in California over the past decade, yet current market rules still prevent them from being compensated for the full value they're able to provide. Many of these market rules were established years ago and are not designed to account for today's energy landscape, where VPPs are capable of providing capacity at any time during the day – and can do more than simply reduce a customers' load.

There are a number of steps that California can (and should) take to address this issue:

1. Compensate VPPs for Grid Exports

Near the end of 2024, California had approximately 1.3 GW of residential battery capacity,[11] yet only a fraction of this is accessible to grid operators because CAISO currently does not compensate DERs for power that they export back to the grid.

A pilot project by Pacific Gas & Electric Company (PG&E) demonstrated that Tesla Powerwall owners could discharge an average of 4.5 kW during DR events, but the average household load was only 1.2 kW.[12] Even if it's assumed that household load doubles during peak periods, these batteries still have up to 2.1 kW of power they can send back to the grid – about half of their entire capacity.

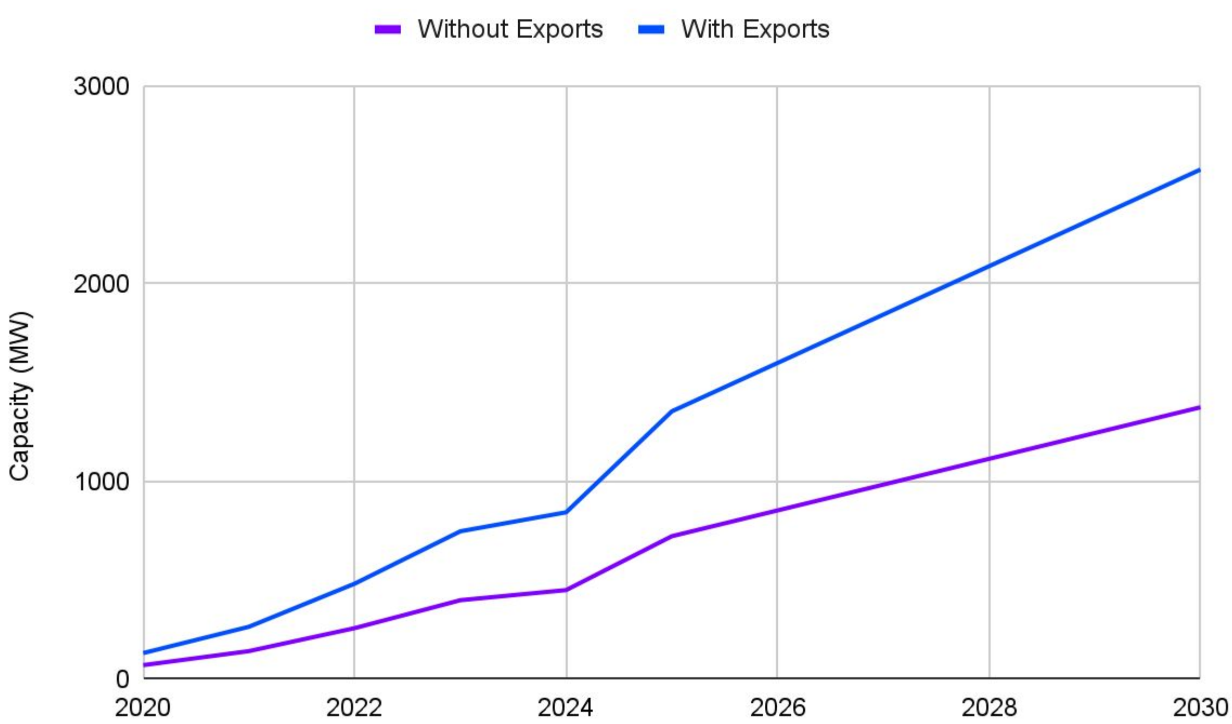
If the findings from PG&E's pilot study hold true across the state, it would mean that close to 600 MW of existing residential battery capacity is unavailable during peak periods because wholesale markets don't currently compensate VPPs for grid exports.

[11] California Energy Commission, "California Energy Storage System Survey." Available here.

The lack of incentives for exporting capacity also discourages participation in RA programs, limiting the revenue potential for battery owners and slowing deployment. With improved compensation, participation would increase significantly, putting California within striking distance of its 2030 Load Shift Goal.

This is because the value of this "hidden capacity" will continue to grow in the future as residential battery installations increase. The latest version of Tesla powerwalls can have power ratings up to 11.5 kW, more than doubling the capacity that they can make available to the grid.[13] Residential battery deployment is also expanding. Based on current trends, residential battery capacity in California will likely exceed 2.5 GW by 2030,[14] at least 1.1 GW of which wouldn't be available to CAISO during peak load days – unless changes are made that allow grid exports to be compensated.

FIGURE 1: Residential Battery Capacity Capable of Being Dispatched by CAISO



[12] Pacific Gas & Electric Company, "DR Emerging technology (DRET) Tesla Battery Study Results," 14 April 2022, p. 2. Available here.
[13] Powerwall 3 Technical Specifications. Available here.
[14] Estimated based on historical data from the CEC's "California Energy Storage System Survey" webpage. Available here.

The impact of compensating exports becomes even more pronounced when considering EVs. California aims to have five million zero-emission vehicles (ZEVs) on the road by 2030.[15] With the growing prevalence of bidirectional charging technology, passenger EVs could contribute significantly to grid exports, boasting an export capacity of approximately 11.5 kW per Level 2 charger.[16] If 10% of these ZEVs were passenger vehicles participating in vehicle-to-grid programs, this would translate to an additional 4.6 GW of dispatchable resources for CAISO if grid exports were compensated.

2. Allow VPPs to Sell Capacity in All Hours of the Day

Currently, DR resources in California are only able to sell capacity during the state's Availability Assessment Hours (AAH), a five-hour period (usually 4-9pm) where the grid typically faces peak demand. The AAH are designed to capture the period of time when capacity is most important, and historically, LSEs have only been required to procure RA during this period. However, under the "Slice of Day" (SoD) framework implemented in 2025, the CPUC now requires LSEs to procure capacity in each hour of the day, representing new operational needs for coordinating large amounts of variable renewable energy on the grid.

However, there has been no change to the capacity allocations for DR resources, which are still only permitted to sell capacity during the AAH. There's no technical barriers for DR resources to provide capacity in more hours. In fact, the SoD framework already has a way to accommodate resources with similar usage profiles, such as utility-scale batteries.

> DR could be incorporated into the Slice of Day framework in much the same way as utility-scale batteries.

These resources are allowed to provide RA in two four-hour shifts throughout a 24-hour period, with a period in between used to recharge the batteries.

DR could be incorporated into the SoD framework in much the same way as utility-scale batteries. The fact that they are not blocks VPPs from effectively participating in the new SoD framework and prevents DR resources that have available capacity outside the AAH to offer it to the market.

[15] "Governor Brown Takes Action to Increase Zero-Emission Vehicles, Fund New Climate Investments," CA.gov, 26 January 2018. [Available here.]
[16] Emporia Level 2 DC Bidirectional Charger. [Available here.]

EVs, for example, have limited capacity to provide during the AAH because these hours typically overlap with high-priced TOU rates when EVs avoid charging. Allowing these resources to provide capacity outside the AAH would allow grid operators to take full advantage of their load reduction potential.

3. Establish Shorter Dispatch Durations

Currently, most event-based DR programs require DR resources to dispatch for upwards of four hours. For example, CAISO has four-hour testing requirements for DR participating in its RA program, and utility Critical Peak Pricing periods can last up to five hours. These dispatch durations make sense for traditional generation resources that aren't use-limited, but they're out of touch with both current grid needs and resource capabilities.

In the 21st century, peak load management should be applied with a scalpel, not a hammer.

Many customer-sited DERs, such as distributed batteries and smart thermostats, can provide large load reductions for two-hour periods, but they struggle to perform uniformly across four-hour periods without triggering customer discomfort or discharge limits.

Similarly, grid peaks do not conform perfectly to four-hour slices – many system peaks are set by one- to two-hour "super peaks" that occur from 6-8pm, or a similar period.[17]

In the 21st century, peak load management should be applied with a scalpel, not a hammer.

Rather than forcing two-hour DER resources to fit into four-hour dispatch periods, DERs should be allowed to reduce load in shorter, more targeted dispatches to trim system "super peaks" – and capture the value of providing capacity in these especially crucial periods.

[17] Southern California Edison – Exhibit 14 – Phase II Rebuttal Testimony, submitted in CPUC proceeding A.22-05-002 et al. on May 12, 2023 (Exhibit (Ex.) SCE-14), at p. 19, lines 2-3.

III. Update Methodologies to Forecast and Measure VPP Participation

Participation requirements for DERs in California's wholesale market must align with how these resources actually operate. California's SSDR programs are some of the more advanced in North America, but they still assume that DR resources can behave like traditional generators and should be treated the same way in the market.

The existing framework relies on a high degree of granularity in forecasting and measuring VPP participation, which might make sense for traditional generators but is inappropriate for aggregations of DERs – and ultimately reduces the capacity available to grid operators. Regulators could take a number of steps to address this issue.

1. Provide More Flexibility for DR Resource Forecasts

Each year, DRPs must estimate their portfolio's future capacity for the next year, based on an enrollment forecast and the prior year's performance. Then, three months prior to the delivery month, the DRP must forecast which sub-Load Aggregation Point (sub-LAP) their customers will be located in, so that they can request that level of "net qualifying capacity" (NQC) from the CPUC.

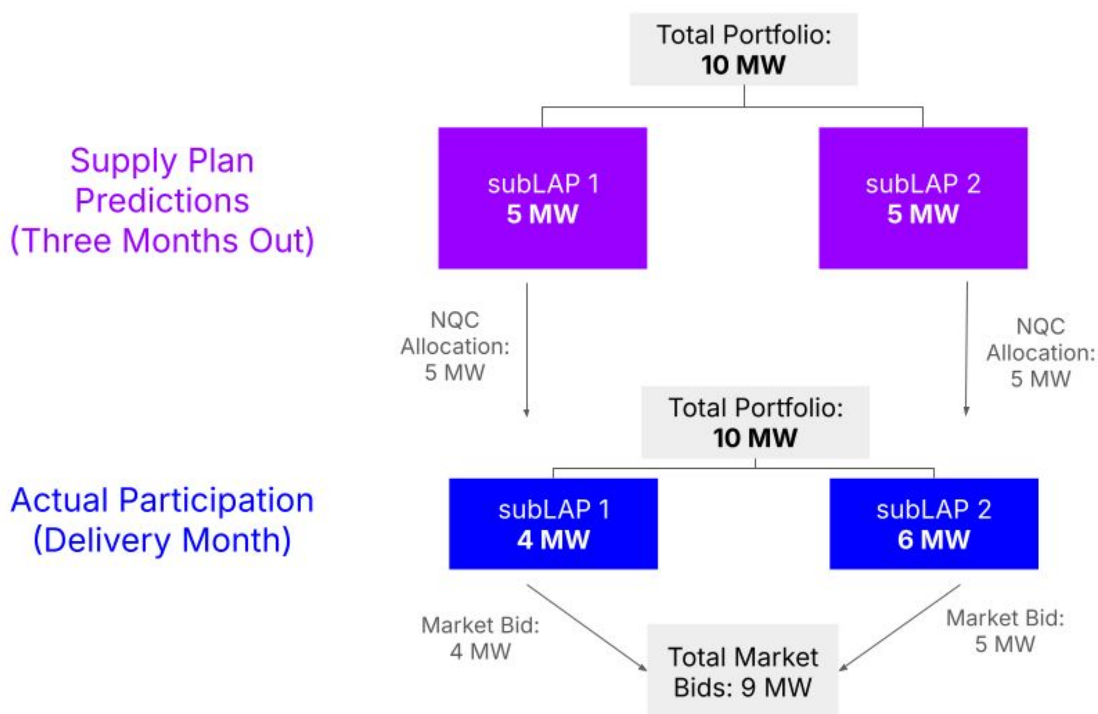
The assumption here is that a DRP knows exactly which customers will install DERs and participate in a DR program 90 days in advance. Once a DRP has submitted their forecast, the resource architecture is fixed and cannot be changed, even if the actual customers that participate during the delivery month are in different sub-LAPs than originally forecasted.

In practice, forecasting with this level of granularity is extremely difficult. It's also unnecessary because most DR resources are providing load reductions at the CAISO system level, which means the capacity they provide is not tied to the sub-LAP they're in. However, because of the forecasting requirement, the resources that DRPs participate in CAISO's market often do not perfectly match the characteristics in their portfolio. This reduces available flexible capacity because any resource exceeding its assigned NQC cannot offer that extra capacity in the market.

The image below shows a simplified example of this issue. A DRP may predict that a 10 MW portfolio will be evenly split between two sub-LAPs, and request 5 MW of NQC for each when it submits its supply plan three months out. However, in the delivery month, 4 MW may come into the first sub-LAP and 6 MW into the second.

Because each sub-LAP cannot participate more capacity than its 5 MW NQC allocation, the DRP can only participate 4 MW from the first sub-LAP and 5 MW from the second sub-LAP. The end result is that 1 MW never makes it to market, simply because that MW came into a different sub-LAP than the DRP had forecasted when it submitted its supply plan.

FIGURE 2: Example of DRP Supply Plan Submissions vs. Delivery



Many DRPs enroll new customers through advertising and outreach, but even if this outreach is targeted, it's hard to know exactly where new participants will be located. Although forecasts are generally accurate at the state or even utility level, forecasting at a more granular level is challenging.

This not only removes capacity from the market, but DRPs may also be assessed performance penalties for underdelivery on the Resource ID level, even though their aggregate portfolio may be more than adequate to cover the CAISO system-level obligations.

2. Implement Prescriptive Baselines

Electricity grid operators can easily measure the performance of generation resources, but DR resources require a baseline to determine what their consumption would have been without a DR event. Traditionally, DR programs have used backward-looking baselines based on a site’s energy use in the days preceding an event, which worked well for large industrial users with predictable demand.

However, with the rise of distributed energy resources (DERs) like batteries, EVs, and smart thermostats, this method is proving inadequate. These technologies can participate in DR events almost every day, making it more challenging to identify enough historical non-event days to establish a baseline.

A more practical solution is prescriptive baselines — predefined estimates of customer load based on historical data from similar users. Unlike traditional methods that rely on past behavior, prescriptive baselines use analysis of average customer load to determine what a DR participant's load would typically be under certain conditions.

Programs like DSGS have already begun using prescriptive baselines for specific technologies, demonstrating their effectiveness in simplifying performance measurement while maintaining accuracy.

This approach significantly reduces complexity in performance calculations while ensuring that frequent DR participants are not penalized for their regular dispatches.

Programs like DSGS have already begun using prescriptive baselines for specific technologies, demonstrating their effectiveness in simplifying performance measurement while maintaining accuracy. By refining and expanding their use, DR programs can provide streamlined, accurate DR measurements that encourage more consistent participation from DERs. This shift would allow DR resources to play a greater role in supporting grid reliability without the distortions caused by outdated measurement methods.

Regulatory Actions

California's demand response sector is overseen by a number of different regulatory bodies, but the three most connected to SSDR are the **California Independent System Operator (CAISO),** the **California Public Utilities Commission (CPUC)**, and the **California Energy Commission (CEC).** These entities have jurisdiction over different components of the regulatory changes identified above, and coordination between them will be required to remove barriers that currently exist. This section outlines what each agency can do to advance the state's Load Shift Goal by incorporating more VPPs into the state's wholesale market.

CAISO

CAISO operates and manages California's markets for grid services, and it is closely involved in grid planning and resource procurement to make sure the state has enough capacity to reliably meet its energy needs. As the market operator, CAISO can create significant changes simply by allowing new approaches for VPPs to participate in the wholesale market. It has also recently launched a new working group focused on better integrating DERs into its market.

One beneficial change this working group is developing is the Modified Proxy Demand Resource (mPDR) mechanism, a new approach to wholesale market participation that would **compensate VPPs for grid exports**. This mechanism would allow VPPs participating with CAISO to have their performance measured at the sub-LAP rather than individual meter level, allowing DR customers to export to the grid as long as net load at the sub-LAP remains positive. If implemented, this change would go a long way to unlocking the full value that exporting DERs can provide to the grid.

The working group is also considering alternative baseline methodologies, which could set the stage for CAISO to accept the use of **prescriptive baselines**. One significant step CAISO could take in this direction would be to move its baseline rules out of its Tariff and into its Business Practice Manual. Since the latter doesn't require approval by the Federal Energy Regulatory Commission to change, this would both help CAISO add prescriptive baselines as an approved methodology and continue to update them in the future to make sure these baselines accurately reflect current customer load patterns.

Similarly, CAISO could enable **device-level measurements** by accepting data provided directly from devices, and allowing customers to authorize that device-level data sharing outside of the utility ShareMyData process. This would need to be done with appropriate standards around accuracy and data security, which CAISO could take the lead in defining.

Finally, CAISO currently determines the process by which DRPs allocate their portfolios to specific sub-LAPs, and it could **provide more flexibility for DR resource forecasts** either by allowing those forecasts to be done closer to the delivery month, or by allowing minor changes to those forecasts as that month approaches.

	Disintermediate Customer Data Access	Adjust Wholesale Markets to Fully Account for VPP Capabilities	Update Methodologies to Forecast and Measure VPP Participation
CAISO	Develop rules and standards to accept device-level data outside of utilities' data authorization processes.	Implement a new mechanism to compensate DERs for grid exports.	Move baseline rules to Business Practice Manual and develop prescriptive baseline options.

CPUC

The CPUC plays a central role in California's electricity sector, setting rates and regulating the state's investor-owned utilities (IOUs). It also manages the RA program that the state uses to secure generation capacity, a role that provides the CPUC with significant leverage in how VPPs participate in California's wholesale market.

For example, if CAISO implements the mPDR mechanism described above, the CPUC may need to approve mPDR as an eligible RA construct in order for it to effectively **compensate VPPs for grid exports.**

Similarly, the CPUC manages the process by which DR resources are allocated NQC for market participation, and it could advance the sector by allowing DR resources to be compensated for **providing capacity in all hours of the day.** There are no technical modifications required to the CPUC's NQC allocation process to do this; the CPUC would simply need to change its NQC counting practices to consider the varying profiles of DR resources that can provide capacity outside 4-9pm. Both this and **shorter dispatch durations** could be enabled by the CPUC as it continues to administer and refine the state's new SoD RA framework.

Finally, the CPUC also has an important role to play in the development of a **statewide data access platform**. Since this platform would host data from the state's IOUs, the CPUC has the authority to require the IOUs to share customer meter data with a centralized platform. In addition, because the statewide data access platform could only achieve its purpose if the data it hosts is sufficiently accurate and up to date, the CPUC should place clear requirements around the speed and accuracy with which this data is shared, with penalties in place if those requirements are not met.

	Disintermediate Customer Data Access	Adjust Wholesale Markets to Fully Account for VPP Capabilities	Update Methodologies to Forecast and Measure VPP Participation
CPUC	Authorize development of a statewide data access platform to host utility data. Create standards for the frequency and accuracy with which utilities share data with new platform.	Evaluate and assign net qualifying capacity for VPPs across all 24 hours of the day. Allow DR resources to dispatch for shorter durations (e.g. 1-2 hours).	

CEC

Although the CEC does not directly regulate the DR sector, it can still play an important part in addressing many of the identified regulatory barriers. The CEC has actually already been testing several of the recommendations above – including prescriptive baselines, shorter dispatch durations, export compensation, and device-level measurements – as part of its DSGS program. The CEC should build on this work by publishing reports on DSGS' results to detail the benefits (as well as any unresolved challenges) of implementing these changes on a wider scale.

The CEC could also play a more active role in enabling the broader use of **prescriptive baselines** in California, as it already receives anonymized customer meter data from utilities, albeit several months after the meter is read. The CEC could use this data to construct prescriptive baselines for different technology and customer types under different conditions, updating them ahead of each DR season based on new analysis of historic customer load.

CAISO and other program operators could then use these baselines to evaluate DR performance, enabling operators to use these resources more frequently and effectively. This somewhat mimics the way that the CEC currently interacts with CAISO to set RA procurement obligations. In this process, CAISO uses electricity forecasts prepared by the CEC to determine how much capacity each load-serving entity in California must procure.

Since the CEC already has experience with handling large amounts of customer data, it would also be the perfect host for a **statewide data access platform**, which could leverage its existing experience with data pipelines and security standards. The CEC is already overseeing the development of a statewide tool that will allow third-party providers to access information on customer rates,[18] which customers can share with those providers to help them determine potential cost savings.

Expanding this tool to also include customer load data would not only support this original objective, but would also allow the tool to further advance the state's Load Shift Goal by helping DR providers to enroll more customers in SSDR programs.

	Disintermediate Customer Data Access	Adjust Wholesale Markets to Fully Account for VPP Capabilities	Update Methodologies to Forecast and Measure VPP Participation
CEC	Manage and host a statewide data access platform for both utility and device-level energy load data.		Develop prescriptive baselines for different customer and technology types using historic customer data.

[18] California Energy Commission, "2022 Load Management Standards Rulemaking FACT SHEET." Available here.

Conclusion

California has an opportunity to unlock the full potential of DR by addressing key barriers such as data access, restrictive bidding rules, and rigid regulatory structures. The current reliance on utility-controlled data platforms creates delays and inefficiencies, preventing customers from fully utilizing their own energy data to participate in DR programs. Additionally, outdated market rules, including limits on battery exports, restrictive capacity bidding windows, and lengthy dispatch duration requirements, reduce the effectiveness of DERs and prevent customers from fully benefiting from their energy investments.

Updating regulations to reflect the capabilities of DERs would allow for greater market participation and improved grid reliability. Streamlining data access, refining bidding structures to allow participation beyond narrow time windows, and introducing more flexible performance measurement methodologies would better align incentives with real-time grid needs, as well as support strong DR performance during market dispatches. Reducing unnecessary granular forecasting requirements would also eliminate inefficiencies that currently limit DR's scalability. As California moves toward a more dynamic and resilient energy system, these changes will be essential for ensuring that DR can serve as a reliable, cost-effective resource.

By leveraging lessons from successful programs like DSGS, California can improve its DR framework and enhance market competition. Simplifying baseline methodologies, utilizing device-level data for performance measurement, and expanding participation opportunities for DERs would create a more inclusive and effective DR ecosystem. Addressing these challenges will not only support the state's clean energy goals but also empower customers to play a more active role in managing grid demand, ultimately leading to a more resilient and efficient electricity system.

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Leap is the leading platform for launching and scaling virtual power plants (VPPs). Through its software-only solution, Leap facilitates fast, easy, and automated access to demand response and other grid services revenue streams for the providers of battery storage systems, EV chargers, smart building technologies and other distributed energy resources (DERs).