May 10 | 2021

EVs and DR:

VGI-DR Workshop Report

Contents

Introduction

On December 21, 2020, the California Public Utilities Commission (CPUC or the Commission) issued Decision (D.) 20-12-029 ("Decision Concerning Implementation of Senate Bill (SB) 676 and Vehicle-Grid Integration Strategies" (the Decision)) in Order Instituting Rulemaking (OIR, Rulemaking, or R.) 18-12-006. The Decision mandates the implementation of various strategies to maximize vehicle-grid-integration (VGI) by January 1, 2030, in accordance with SB 676. "The concept of utilizing EVs to provide demand response comports with the definition of VGI adopted by this decision as it would allow EVs to provide grid services during times of critical strain on the grid."[1]

A potential venue for "deployment of VGI to provide demand response" identified by the Commission may be the next Demand Response (DR) Application filed by the three electric investor owned utilities (IOUs).[2] In the next DR Application, the IOUs will propose changes to existing DR programs, or new DR programs, with accompanying budget requests. Pursuant to D.17-12-003, the next DR Application will be effective for program years 2023 through 2027 and is expected to be filed November 1, 2021.

Overview

In compliance with the Decision, on March 9, 2021, the three large electrical California IOUs and the CPUC's Energy Division (ED) hosted a Vehicle-Grid Integration (VGI) DR workshop to educate potential VGI DR providers on existing DR options for electric vehicles (EVs), identify barriers to participation in DR for EVs, and explore how to overcome those barriers to expand EV participation in DR in the future.

The workshop was moderated by Pacific Gas & Electric Company (PG&E), with introductory remarks from the CPUC. Presenters included the three IOUs - PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) - the California Energy Commission (CEC), BMW, Enel X North America (Enel X), and Olivine.[3]

The workshop was comprised of presentations and conversations on various topics including current DR options available for EVs, barriers to EV participation in DR, and lessons learned thus far from EV studies and pilots. Online polls were also used during the workshop to heighten engagement and gather feedback in a quantifiable format. Information about the workshop was posted on LinkedIn. In addition, email invites were sent directly to:

- CPUC Service lists R.18-12-006 (Development of Rates and Infrastructure for Vehicle Electrification OIR), A.17-01-012, et al. (2018-2022 DR Application), and R.13-09-011 (DR OIR).
- Current IOU Demand Response Providers (DRPs) – also known as Aggregators – and technology partners.
- Potential IOU DRPs and technology partners.

[1] D.20-12-029. Page 33.
[2] Id.
[3] See the Appendix section of this report for the distributed Workshop agenda.

The workshop's scope included three topics, followed by an open discussion focused on how to address the barriers to EV participation in DR:

- DR Basics and Eligibility.
- Known Barriers to EV Participation in DR.
- Lessons Learned from EV Participation in DR.

Additionally, four anonymous polls were made available to attendees throughout the workshop:

1. How Well Do You Know DR?
2. What Are Your Initial Thoughts on Existing DR Programs?
3. What is Your Experience of Barriers to EV Participation in DR?
4. Where Do We Go From Here?

The following is a timeline of workshop related activities:

- February 26, 2021: Notice of workshop's date, time, and location delivered via Microsoft calendar invite.
- March 5, 2021: Agenda attached to the calendar invite; updated version delivered.
- March 9, 2021: Workshop event, 1pm-4pm (Pacific).
- March 11, 2021: Presentation in PDF format circulated to participants.
- May 10, 2021: Report published.

DR Basics and Eligibility

On behalf of the IOUs, PG&E presented on the basic concepts of DR, including:

1. Distinguishing between Proxy Demand Resources (PDRs) and Reliability Demand Response Resources (RDRRs).
    a. A PDR is bid into the market as an economic resource, and "participates in the CAISO comparable to a supply resource."[4]
    b. A RDRR is a reliability resource expected to respond in real-time, which "enables CPUC jurisdictional emergency responsive demand response resource participation in the [CAISO] market and operations."[5]
2. How DR programs are market-integrated.
    a. Market-integration refers to the process of bidding demand response resources into the CAISO wholesale energy market. "The energy products and services traded in our market allow us to meet reliability needs and serve load."[6]

[4] CAISO. "Proxy Demand Resource (PDR) & Reliability Demand Response Resource (RDRR) Participation Overview." Slide 3.
[5] Id., Slide 4.
[6] CAISO. "Market processes and products."

The presenters then described the IOUs' current EV-eligible DR programs, pilots, and rates. The presenters noted that while the IOUs' DR programs and pilots are different in some respects, there is consistency in some DR options across the IOUs. Each IOU then shared specific EV-eligible DR programs, pilots, studies, and incentives that are unique to its service territory.

Known Barriers to EV Participation in DR

Primary barriers that have been identified through pilots and conversations with stakeholders were presented. Background on why each barrier exists and how it impacts EVs was discussed. There were four barriers presented:

1. **DR Baselines**
   EV charge sites across sectors may not have consistent charge patterns during DR program hours.
2. **TOU Participation**
   EV charge owners may already be configured for TOU participation to optimize rate savings, which limits their ability to deliver additional load reduction for DR events.
3. **Hours of Availability**
   Not all EVs can provide load drop for the required 4 hours to meet Resource Adequacy (RA) requirements.
4. **Export**
   Demand < 0 is not counted toward DR performance or compensation.

Lessons Learned from EV Participation in DR

Organizations who have experience with EV participation in DR presented, including:

1. BMW
2. CEC
3. Enel X
4. Olivine

Various scenarios and studies were used to illustrate lessons learned, as well as to further explore the specifics of barriers to EV participation in DR, and how to overcome those barriers.

Existing DR Opportunities for EVs

The first presentation in the workshop covered the existing opportunities for EVs to participate in demand response rates, programs, pilots, and studies across IOUs. While some options are structured such that one or more barriers prevents successful EV participation, some may be feasible for DRPs or EV owners who are not yet aware of those options. This was a presentation focused on educating potential participants about the basics of these opportunities.

All-IOU Rates, Pilots, and Programs

Demand response provides savings or incentives to customers – either directly or through a Demand Response Provider (DRP) – to reduce energy use during periods of high demand or energy prices. It improves grid reliability without producing emissions by **managing peak energy and evening ramps**. There are many DR options available for customers and DRPs. The following DR rates, pilots, and programs are a subset of existing DR options that allow EV participation.

Critical Peak Pricing (CPP)

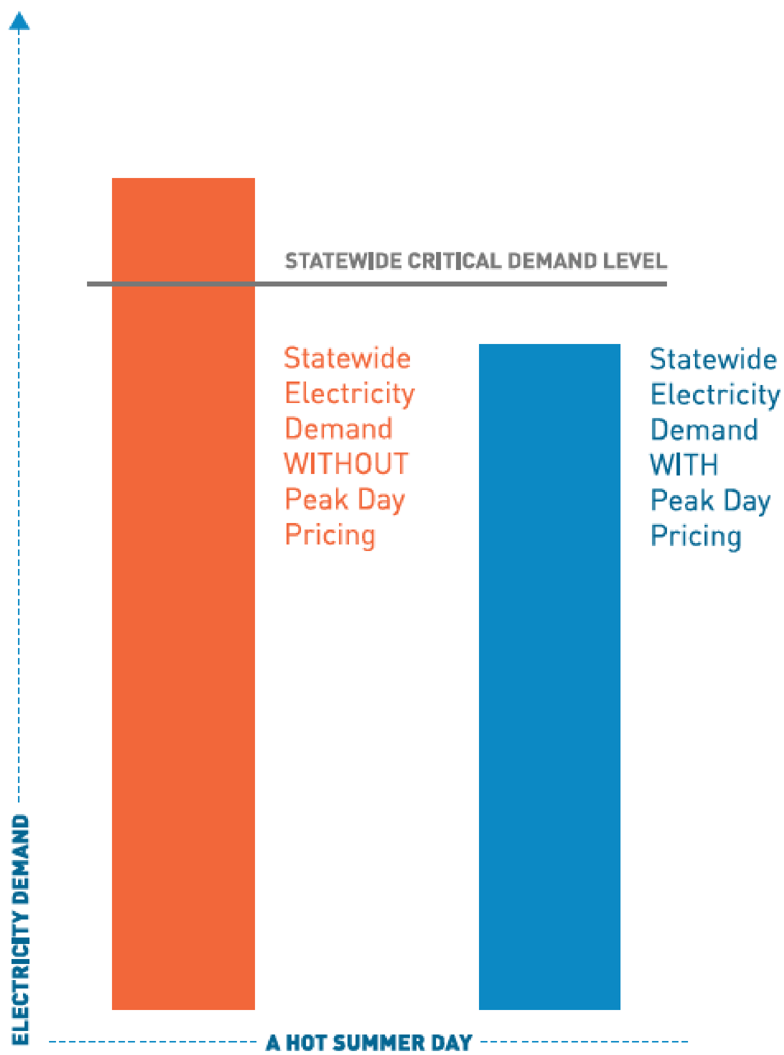

FIGURE 1 STATEWIDE CRITICAL DEMAND LEVEL WITH PDP VS. WITHOUT PDP

CPP rates provide incentives in the form of bill credits to customers on top of TOU rates to receive a day-ahead notification to reduce demand during CPP events and avoid higher-than-usual rates. Eligible customers are those receiving bundled electricity service from an IOU.[7] CPP is not a DR *program*, and is out-of-market. This means that participants are not bid into the CAISO market as PDR or RDRR resources, but are instead dispatched by higher-than-average forecast temperature. CPP events may also be called in cases of forecasted system emergencies, or high load and/or price forecasts. Eligible customers can enroll directly into these rates with the IOU. It is not an option for DRPs.

The Summer Reliability OIR (D.21-03-056)[8] approved a variety of changes for CPP, which were presented in a Demand Response workshop jointly hosted by the IOUs and Community Choice Aggregators (CCAs) on April 6, 2021.

Links to the CPP webpages:

SDG&E

PG&E

SCE

[7] RESA. “Energy Glossary.”
[8] CPUC. R. 20-11-003.

Capacity Bidding Program (CBP)

CBP is an economic PDR program, which means that CBP resources are bid into the CAISO day-ahead market and CBP events are triggered by CAISO market awards based on price. For example, a CBP resource might be bid into the CAISO day-ahead market at $95/MWh; if CAISO day-ahead market prices exceed $95/MWh, the CBP resource will likely be dispatched to reduce demand. CBP program options vary between IOUs, including a day-ahead only or a day-ahead and day-of notification option. Participants receive capacity incentives based on the monthly capacity price and their nominated MW, which is adjusted for performance during events in that month. Participants can also receive energy payments for their performance during actual market events. This is an Aggregator-only program, with the IOU acting as the scheduling coordinator for bidding into the CAISO market.

Both residential (home chargers) and non-residential (public, fleet, or workplace chargers) EV Aggregators are eligible to participate in CBP. However, the current program structure may deter EV Aggregators from participating. For instance, baselines are used to measure event performance (5-in-10 for residential, 10-in-10 for non-residential);[9] the RA hours overlap with TOU hours; the resource may need to be available for as long as 8 hours, in which the resource must be available for up to 4 hours; and exported energy is not counted toward event performance.

Several IOU-specific changes were approved for CBP in the Summer Reliability OIR, including adoption of 5-in-10 residential baselines and increases to some capacity incentives.[10]

View current CBP Aggregators open to new enrollments on the CBP webpages:

SCE CBP

PG&E CBP

SDG&E CBP

Demand Response Auction Mechanism (DRAM) Pilot

DRAM procures monthly RA capacity from 3rd party demand response providers (DRPs). The DRP is the scheduling coordinator and bids its resources directly into the CAISO market as PDRs. DRAM capacity is procured through an annual Request for Offer (RFO) process, in which DRPs can submit offers for the following delivery year.

Learn more about the 2022 DRAM RFO process on the DRAM webpages:

SDG&E

PG&E

SCE

[9] 5-in-10 looks at the last 10 similar days and then use only the 5 with the highest demand to create a baseline; 10-in-10 looks at the last 10 similar days to create a baseline.
[10] D.21-03-056. Attachment 1. P 19-20.

Emergency Load Reduction Program (ELRP) Pilot

The ELRP is a new pilot recently approved in the Summer Reliability OIR, for 2021-2025. It will be an out-of-market option, with events triggered by CAISO Alerts, per the "Alert, Warning, Emergency" (AWE) notification process as defined by CAISO Operating Procedure 4420.[11] ELRP events can only be dispatched by the CAISO AWE process; IOUs cannot use ELRP for localized transmission or distribution emergencies.

Currently, ELRP includes a day-ahead notification option, but may change in the future to also include a day-of notification option. It allows dual participation with certain other DR. The ELRP season will run May-October, 7 days/week, from 4-9pm. Only incremental load reduction will be counted toward a participant's ELRP performance, with an incentive of $1 per kilowatt per hour (kWh). Participation is voluntary, and there will not be penalties or capacity payments.

Additionally, in the Summer Reliability Decision (D.21-03-056) issued on March 26, 2021, the CPUC noted support for exporting capabilities permitted by Rule 21 to participate in ELRP, and stated: "[W]e believe it is reasonable to explore the issue of how EV aggregations with export capability could be leveraged as DR to provide grid services, and an upcoming workshop ordered by D.20-12-029 [i.e. the VGI DR Workshop] may provide an opportunity for that discussion."[12]

Pursuant to D.21-03-056, the IOUs are directed to jointly submit two Tier 1 Advice Letters to implement ELRP for 'Customer Group A' and 'Customer Group B' on April 26, 2021 and May 24, 2021, respectively.[13] These Advice Letters are intended to provide details necessary to implement the ELRP guidelines and address various aspects of ELRP pilot design and processes, including enrollment, the process to update enrollment related program parameters, ELRP event notification and customer acknowledgement, incremental load reduction measurement, and settlement.

Customer Group A includes: Non-residential, Non-DR customers; BIP Aggregators; Rule 21 Exporting DERs; and VPPs.

Customer Group B includes: Third-party DRPs; CBP PDR Resources.

IOU-Specific EV Studies, Pilots, and Programs

There are several DR options for EVs that are only available at some of the IOUs. These options are primarily designed to focus testing and gathering data to inform future DR programs.

SCE

Base Interruptible Program (BIP)

BIP is an emergency DR program that is integrated into the CAISO market as an RDRR. There is only a day-of notification option, and performance is measured against a customer's firm service level (FSL), which is a contractual commitment level. This program is only available to non-residential customers, who can enroll directly or through an Aggregator. **Learn more on the SCE** BIP fact sheet**.**

[11] CAISO Operating Procedure 4420. "System Emergency."

[12] CPUC. D. 21-03-056. P 50-51.

[13] Advice Letters 4478-E (SCE), 6173-E (PG&E), and 3744-E (SDG&E). "Emergency Load Reduction Program Pilot Terms and Conditions of Southern California Edison Company, Pacific Gas and Electric Company, and San Diego Gas & Electric Company in Compliance With Decision 21-03-056." April 26, 2021.

Charge Ready DR Pilot

Participation in this pilot is required for commercial customers who receive rebates on the purchase and installation of EV charging stations as part of SCE's Charge Ready Program. DR participation is a requirement of the Charge Ready Program. A pilot participant's event performance is measured against a calculated baseline. There is only a day-ahead notification option, with an Open ADR signal for events. Open ADR is a standard communication tool created "so that dynamic price and reliability signals can be exchanged in a uniform and interoperable fashion among utilities, ISOs, and energy management and control systems."[14] It makes "the installation of electric vehicle (EV) charging stations easier and more cost-effective for businesses and properties"[15] while enabling customers to automate and simplify demand response for more reliable load reduction during events. SCE recently received CPUC approval to expand the DR pilot to include passenger vehicles in Charge Ready 2. **Visit the** Charge Ready Program site **to learn more.**

SDG&E

Technology Incentive (TI) Program

The TI program helps EV customers pay for controls for commercial accounts, such as OpenADR, by covering up to 75% of project costs. It is available to customers on a commercial, industrial, or agricultural TOU rate. It requires enrollment in CBP, CPP, or DRAM for three years. **Learn more on the SDG&E** Technology Incentives website**.**

Base Interruptible Program (BIP)

BIP is an emergency program for RDRRs. There is only a day-of notification option, and performance is measured against a firm service level (FSL) which is a commitment made at enrollment. This program is only for non-residential customers, who can enroll directly or through an Aggregator. **Learn more on the SDG&E** BIP website**.**

PG&E

As recommended by the VGI Working Group, these studies will demonstrate the capacity and availability of direct enroll and aggregated EVs using open standards.[16]

Non-residential Automated Demand Response (ADR) Program

Similar to SDG&E's TI program, PG&E's ADR program provides incentives to any non-residential customer for installing or upgrading OpenADR technology, and pays as much as $200/kW of potential load shed. Participants can be enrolled directly or with an Aggregator, and must participate for three years in one of the following qualified DR programs: PDP, CBP, or DRAM. **Learn more on the PG&E** ADR website.

[14] openADR Alliance. "Overview."

[15] SCE. "Charge Ready Program."

[16] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group. June 30, 2020. California Public Utilities Commission DRIVE OIR Rulemaking (R.18-12-006). P 38.

Residential ADR EV Study

The ADR EV Study will be conducted during the summer of 2021 with three vendors: ChargePoint, Enel X, and Geotab. A limited group of residential customers will be selected to participate, including single-family homes and multi-unit dwellings. The study will conduct 4-hour DR events and plans to measure performance with a Randomized Control Trial (RCT) design. The goal is to determine appropriate ADR incentives for residential EVs, and gather usage data. It will be out-of-market. A report with the findings of this study will be published January, 2022. For more information, contact Wendy Brummer – **wendy.brummer@pge.com**.

Aggregated EV Study

An Aggregated EV Study will be conducted in 2022 to determine DR program components critical to the success of DR participation for aggregated EVs. It will focus on aggregations of chargers on non-residential rates, such as workplaces and multi-unit dwellings. The goal will be to test solutions to the various barriers to EVs participating in DR, such as event duration and performance measurement. Participants and details have yet to be determined. For more information, contact Nicolette Sowa – **nicolette.sowa@pge.com**.

Barriers

While the workshop examined known barriers to EV participation in demand response, it should be noted that many of these barriers are foundational to CPUC policies (e.g., DR bifurcation[17]). Because of these policies and operational requirements, the barriers identified in the workshop may only be resolved in conjunction with policy and other foundational changes that are beyond an IOU's purview. If EV resources are going to participate and become supply-side DR resources, issues around DR baselines, forecasting challenges, resource adequacy, and incrementality will need to be part of a comprehensive solution, such that the modification or creation of retail rates and programs alone will not be sufficient.

DR Baselines

Performance during a demand response event is typically measured against a customer baseline, such as the average of the previous 10 days or the monthly average of customer demand during the on-peak grid hours of 4pm-9pm. Using a baseline to measure performance attempts to estimate incremental demand reduction during a DR event compared to what demand would have looked like absent an event. It has been used to provide "accurate estimates of a customer's peak load reduction," which can then be used for settlements, resource planning, and cost-effective evaluation.[18]

[17] In early 2014, the Commission conceptually bifurcated the demand response portfolio into load modifying and supply resources in D.14-03-026. Later that same year, the CPUC issued D.14-12-024 which adopted a modified proposal and established several working groups charged with looking at the integration issues of DR supply-side resources and acknowledged the technical complexities of integrating DR into the CAISO market.

[18] CPUC. "Baselines for Retail Demand Response Programs." Bruce Kaneshiro. Slide 2.

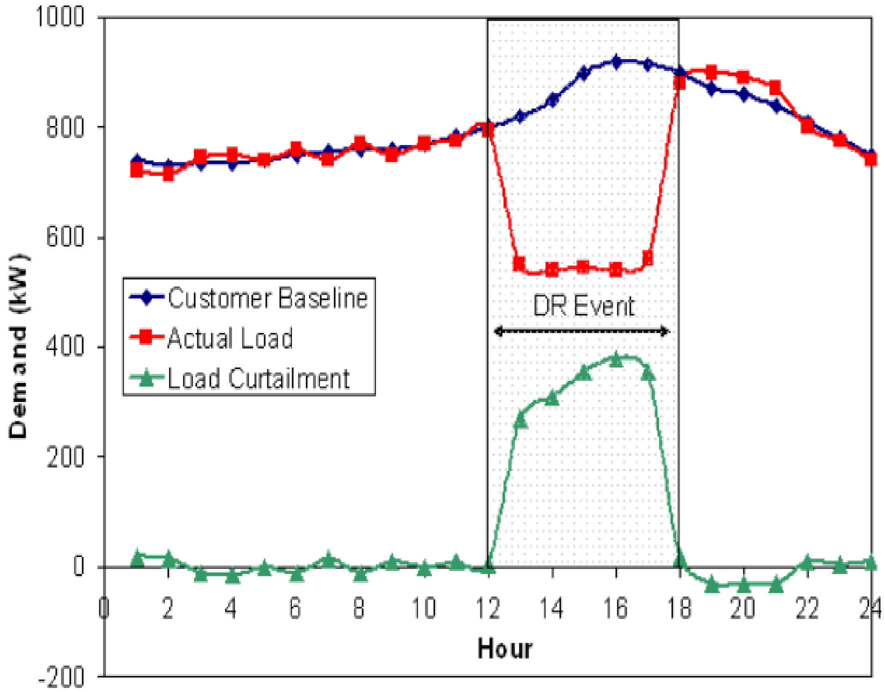

FIGURE 2 PERFORMANCE MEASURED AGAINST BASELINE

Current baselines work well for sites with consistent load during the hours in which a demand response event is called. However, EV chargers and owners do not always have consistent load against which to measure a reduction in demand. For example, at a public charging station, there may not be enough EVs in the area to have demand that is steady, the incentive to site owners to reduce load during a DR event may not outweigh the customers' charging needs, or there may not be additional load to drop depending on the configuration of the charging stations.

As another example, at a residence, the owner may not have a set charging schedule, may not have the technology tools that sufficiently support DR events, or may desire flexibility to charge the vehicle regardless of grid conditions. Additionally, EV charging at the home is generally tied to demand for the entire premises, so charging avoidance does not necessarily equate to reduced demand on the meter in the absence of a separate meter. For example, BMW found in its ChargeForward Phase 2 Pilot with PG&E that an "[i]ndividual vehicle baseline [is] subject to high variance." On the other hand, if EV charging sites at non-residential locations are separately metered, the premises, including any on-site energy storage, cannot be utilized to further reduce or balance demand from the chargers.

For residential customers, submetering may be a solution to ensure separate measurement of EV performance from the premises. "Electrical submetering is the measurement of consumption after the master meter," and provides "granular measurement of energy use, right down to the individual circuit."[19] For DC fast charging and Level 2 charging stations, Olivine determined that "[b]aselines [will] tend to be erratic and often problematic until increased EV market saturation occurs and baselines stabilize." For all EV customers, Enel X pointed out that new RA constructs and incentives will be needed to maximize demand reductions during peak hours.

[19] Triacta. "Electrical Submetering in California: Fact, Fiction and Folly."

Workshop participants also noted that enabling exports from EVs will reshape how baselines are calculated. Designing retail programs that do not require a commitment with a price signal that shifts demand may be a solution, such as an out-of-market option for load modifying resources (LMRs). For DR programs designed to allow export, the baseline could potentially be set at zero.

In summary, potential pathways to overcome the barrier of DR Baselines in the IOU DR programs include:[20]

1. Sub-metering.
2. Enabling export functionality.
    a. For both EVs and EVSE charger technologies.
3. Out-of-market (LMR) incentives.
4. Performance measured by incremental load reduction.

TOU Participation

Time-of-Use (TOU) rates allow customers to choose time windows to avoid charging when it fits best with their schedules and with grid needs. This both reduces costs for customers and reduces strain on the grid during high-demand periods on a daily basis.

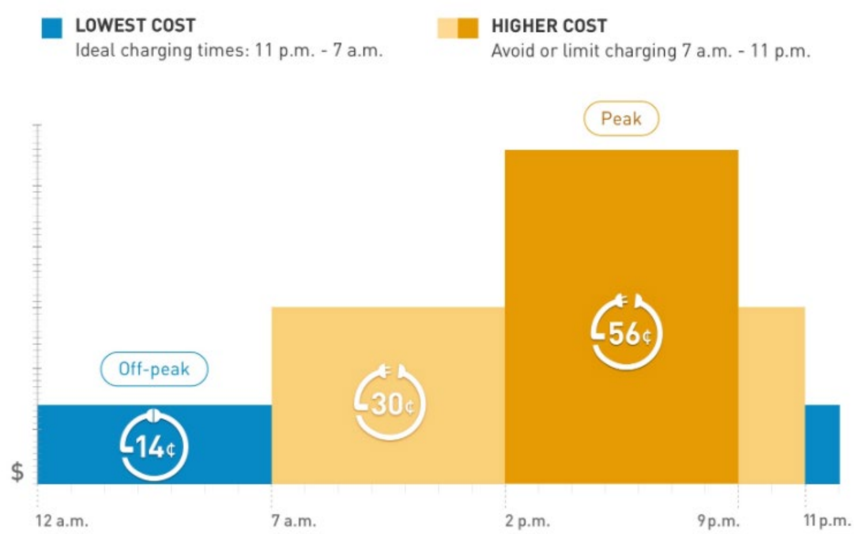

FIGURE 3 TOU RATE EXAMPLE

Additionally, as recommended by the VGI Working Group,[21] both residential and business EV rates are now offered at all of the IOUs:

SDG&E: Residential / Business

PG&E: Residential / Business

SCE: Residential /Business

[20] Also see the "Possible Actions" section of this report.
[21] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group. June 30, 2020. CPUC R.18-12-006. P 38.

However, TOU windows often overlap with DR program windows. This is because both are trying to mitigate high-demand periods, especially the RA window from 4-9 pm, which are the hours in which DR must be available to count toward a load serving entity's (LSE) maximum cumulative capacity (MCC).[22] If EV participants are already lowering or avoiding charging daily during a TOU window, they likely cannot contribute incremental load reduction for a DR event, nor can a baseline be established relative to DR event hours to estimate incremental load reduction.

Residential customers may generally be able to avoid charging completely during TOU hours, but non-residential sites may need to have charge capability at some level at all hours. Residential customers might be compensated for 'non-use' hours, which could be determined at a local or system level. In fact, as noted by a workshop participant, residential peak hours start closer to 8 pm, when output from solar PV is dwindling.

Non-residential customers might be offered a battery-stacking option, in which they could be incentivized to install batteries on site to reduce demand during events while maintaining the ability to provide charging services, and/or may be able to further shift load off-peak given a sufficient incentive. For instance, if a transit vehicle or other vehicle would be needed to charge during peak periods to fully recharge but did not need to fully charge every day, it could potentially defer charging during a DR event for a given day. Or a vehicle could potentially use public charging during the day that is normally more expensive. For both residential and non-residential customers, load control incentives could be offered, which would ensure optimization and response to local grid needs hour by hour.

In summary, potential pathways to overcome the barrier of TOU participation in IOU DR programs include:[23]

1. Optimization incentives.
2. Battery-stacking options.
3. Enabling export functionality.
4. Out-of-market (LMR) incentives.
5. Performance measured by incremental load reduction.

Hours of Availability (Resource Adequacy)

CPUC RA rules require DR resources to be available Monday-Friday, for a minimum of four (4) consecutive hours between 4 and 9 pm, and at least 24 hours per month from May-September.[24] This provides assurance that use-limited resources can provide meaningful impact or load reduction during typical on-peak hours.

[22] CPUC. 2021 Final RA Guide. P 5.

[23] Also see the "Possible Actions" section of this report.

[24] CPUC. 2021 Final RA Guide. P 5.

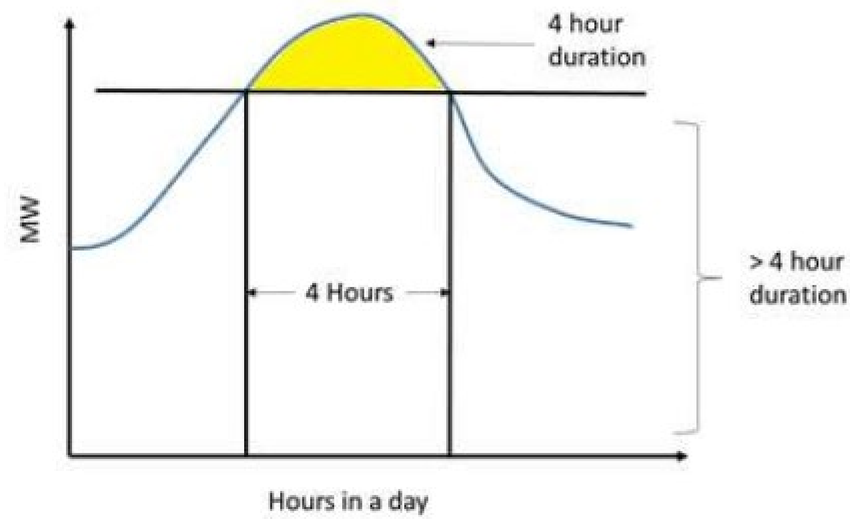

FIGURE 4 REDUCTION TO PEAK DEMAND WITH 4-HOUR DEMAND RESPONSE EVENT DURATION
[25]

However, this requirement does not take into account energy needs across all hours and days.[26] Public EV charging ports and commercial fleets may struggle to commit to reduced or no charging for 4+ hours due to business needs. Residential EV customers may have more variable charging needs, and are not consistently available to respond. Additionally, when coupled with solar, demand may be negative during some or all demand response hours.

BMW's ChargeForward pilot with residential participants found that a set expectation is successful, with "80-99% of participants adher[ing] to required weekly 'no-charge' hours." This indicates that a simple, consistent rule may help customers plan their EV usage around peak demand hours. This approach does not consider local grid conditions, but could be tailored to a more granular level – such as sub-LAP[27] – to mitigate the risk of creating a new problematic peak period during a different time of day. Additionally, if all EVs in a service territory refrained from charging during TOU hours, a new demand peak(s) could start to appear; as saturation of EVs increases, it will be important to optimize demand during all hours.

In summary, potential pathways to overcome the barrier of Hours of Availability in the IOU DR programs include:[28]

1. Aggregated resources.
2. Battery-stacking options.
3. 'No-charge' hours incentives.
4. Out-of-market (LMR) incentives.
    a. Optimization incentives.

[25] CAISO. Resource Adequacy Enhancements Straw Proposal. July 1, 2019. P 38.
[26] Id., P 8.
[27] Sub-LAP stands for "sub-Load Aggregation Points," which are geographic boundaries defined by CAISO that help determine capacity needs for reliability. For more information, see "Demand Response Potential for California SubLAPs and Local Capacity Planning Areas."
[28] Also see the "Possible Actions" section of this report.

Export Functionality

Demand response measures the reduction of demand. However, EVs and many EV chargers can act as batteries, thus providing load to the attached building (V2B) or home (V2H), or even to the grid (V2G), when needed. The VGI Working Group Final Report found that V2G can effectively provide customer backup/resiliency, customer bill management, and system resource adequacy, among other benefits.[29]

Interconnection standards are set via Rule 21,[30] which "provides customers wishing to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmissions systems at the local and system levels."[31] Bi-directional direct current (DC) chargers that go through the interconnection process are allowed to export to the grid if technical criteria is met and the utility approves. However, additional work is required to ensure that EV exports in demand response programs can be measured and incentivized appropriately. Demand response systems and operations might be enhanced for insight into system outages that might prevent successful export during a demand response event.

Exports have also been excluded from demand reduction calculations under the CAISO's PDR and RDRR models. Aside from ELRP, load reduction that includes export does not count toward demand response event performance, and the IOUs do not have guidance on how to properly incentivize exported load for RA.[32] Additionally, not all EVs or EVSE are capable of exporting, and even those that are may not be a large enough presence in the market to provide stable load or reliable exports. Only with accelerated EV technology adoption and appropriate incremental value can exports be folded into DR options and adequately compensated for capacity.[33]

In summary, potential pathways to overcome the barrier of Export Functionality in the IOU DR programs include:[34]

1. Incentives for export.
2. Baselines that include export.
3. Enabling export functionality.
    a. For both EVs and EVSE charger technologies.
4. IOU system and process enhancements.
5. Develop market mechanisms that
    a. Contemplate capacity value payment beyond the baseline.
    b. Enable ancillary services from EVs.

[29] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group. June 30, 2020. California Public Utilities Commission DRIVE OIR Rulemaking (R.18-12-006). P 32.
[30] D.20-09-035.
[31] CPUC. Rule 21 Interconnection.
[32] CPUC. "Capacity Valuation for BTM Hybrid Resource Workshop." November 24, 2020. Slide 67.
[33] CPUC. "Capacity Valuation for BTM Hybrid Resource Workshop." November 24, 2020. Slide 67.
[34] Also see the "Possible Actions" section of this report.

Lessons Learned

BMW

BMW presented findings from their ChargeForward Phase II (2017-2020) pilot with PG&E. OpenADR was used for DR signals with up to 400 EVs and in ten different use cases. They had success in charging during peak renewable periods, which demonstrated significant avoided GHG emissions and increased use of renewable energy. However, barriers related to baseline prevented meaningful DR participation. In particular, variable customer behavior, daily optimization, and whole-home/premises metering proved challenging in creating a baseline. Variable customer behavior was due to EV owners having a variety of schedules and mobility needs, which means that they may not be on the premises during a DR event. Daily optimization, via automated load management (ALM), is a powerful tool to reduce load when prices are high for the customer, helping to reduce customers' energy bills and reduce demand on the grid when needed most; however, those often are the peak TOU hours, making it difficult to reduce additional demand for DR events. Whole home/premises metering proves difficult because it adds "noise" the meter; even if the customer can reduce or avoid charging during a demand response event, if they do a load of laundry or turn up their A/C, the impact of the EV on the demand can be significantly diminished.

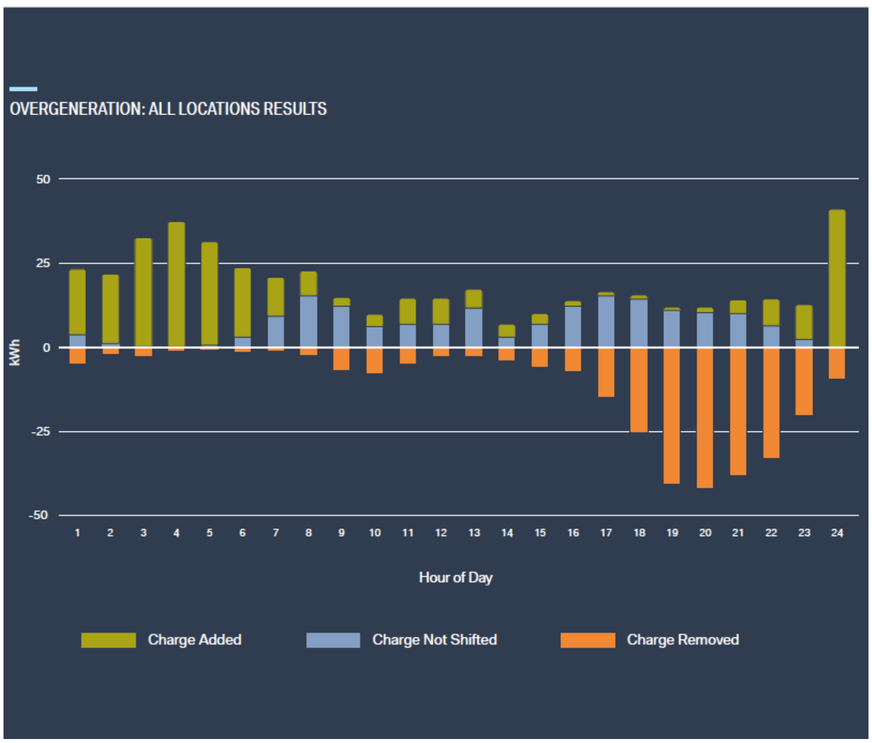

Figure 5 BMW ChargeForward Phase II Results

BMW's recommendation for future EV-DR programs was to "combine events-based signals with incentives for optimization." PG&E is interested in this approach, and will work with BMW in ChargeForward Phase III to explore how best to implement it. They plan to evaluate the ability for customers to respond to 1-hour events vs. 4-hour events, the ability for BMW to dispatch customers who may not be on the premises, various customer incentives, increased customer education, and various methodologies for measuring load reduction during a DR event. In particular, measuring actual load reduction against expected demand during a DR event will be considered, as well as various baselines methodologies such as 10-in-10.

CEC

The CEC presented findings from NREL data in its Electric Vehicle Charging Infrastructure Assessment.[35] LDEVs and MHDEVs across sectors were evaluated to demonstrate how permanent load shift can be achieved with TOU and ALM. Specific to demand response, driver engagement, range anxiety and event windows were barriers to meaningful load reduction.

Like BMW, the CEC recommended program stacking; demand response can be more effective when applied with other load management strategies such as ALM and V2G. Advanced technology that can receive direct load control signals and take into account driver preferences and needs will lead to more effective customer engagement and less range anxiety.

Policies, such as CPUC customer-owned EVSE Submetering Protocol, CAISO PDR use of Separate EVSE Metering, and FERC Order 2222 requirements to enable multi-use applications can be coordinated to shape DR programs that marry the wholesale and retail aspects of submetering. For use cases in which EV load is to be measured separately from the residence or other on-site load, submetering will help create an EV baseline and/or more accurately measure performance in a DR event. These policies also enable shorter durations, which better suit EVs given their variable and on-demand nature.

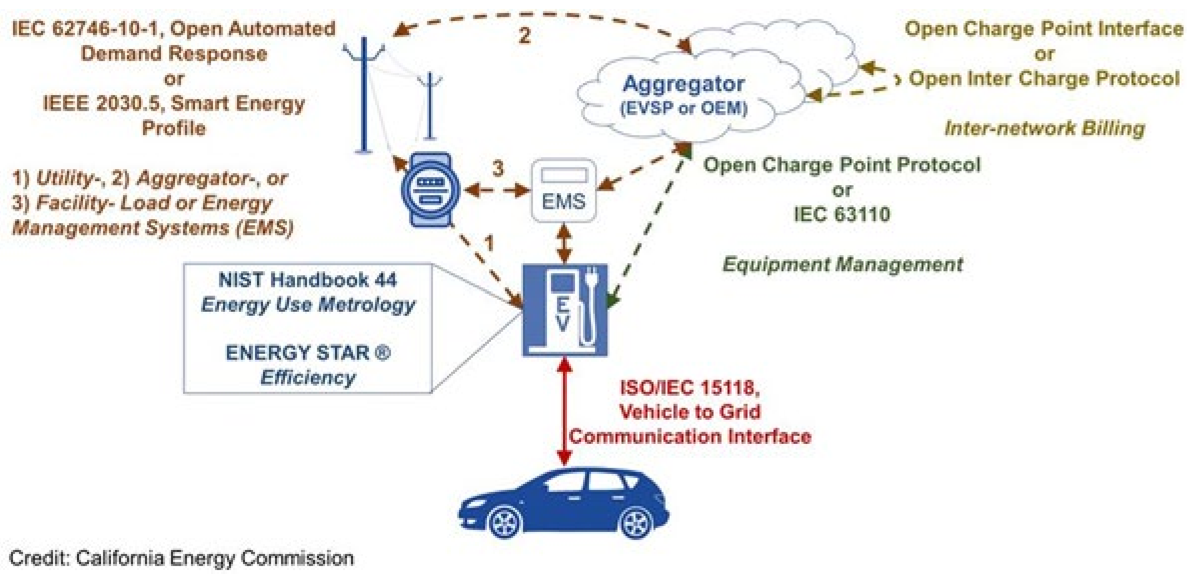

FIGURE 6 CEC RECOMMENDED COMMUNICATION PROTOCOLS TO ENABLE VGI

In order to reduce the overlap of DR events with TOU, different signals for EVs participating in DR might be considered, such as GHG and RTP. These types of signals, coupled with shorter duration events would enable EVs to provide more flexible and localized load reduction outside of the typical peak demand hours. Additionally, size requirements for aggregations <100 kW are key to encouraging participation of residential and small-site EV chargers in DR.

[35] CEC. AB 2127 Electric Vehicle Charging Infrastructure Assessment. Appendix C.

Enel X

Enel X's presentation focused on monetizing capacity and customer experience. It noted that primary barriers to EV participation in DR are the difficulty in creating baselines and inability to export (V2G). Like the CEC, Enel X stated that policy work is needed, specifically around a Multi-Use Application (established in the CPUC Energy Storage Proceeding R. 15-03-011), to continue the work started by the Decision on Multiple-Use Application Issues based on Assembly Bill (AB) 2514.[36] This would help operationalize metering and accounting for non-generating resources (NGRs) participating directly in the CAISO wholesale market with a distributed energy resource provider (DERP).

FIGURE 7 ENEL X SMART EV CHARGING SOLUTIONS

Enabling submetering and new RA constructs are vital in order to adequately measure, incentivize, and forecast V2G resources. However, separate service drops for EVs was raised as an issue, as it prevents several V2G, V2H, and multi-DER use cases. If EV chargers have separate service drops, they cannot interact with the rest of the premises, which prohibits their usefulness as an exporting and resiliency resource. It also limits program-stacking opportunities, such as incentivizing battery storage on site with EV chargers, and opportunities to provide holistic DR options. However, separate service drops do enable different load types in different DR options, which may be useful if load types on a premises – such as A/C use and EV charging – vary significantly from each other.

[36] D.18-01-003. P 2.

Olivine

Olivine presented several use cases, ranging from residential, to buses, to retail settings. Related to demand response, important lessons learned included barriers to creating baselines due to the inconsistent usage at DCFC sites, reduced evening load at workplace charging sites, and TOU hours for residential participants that overlap with typical DR events.

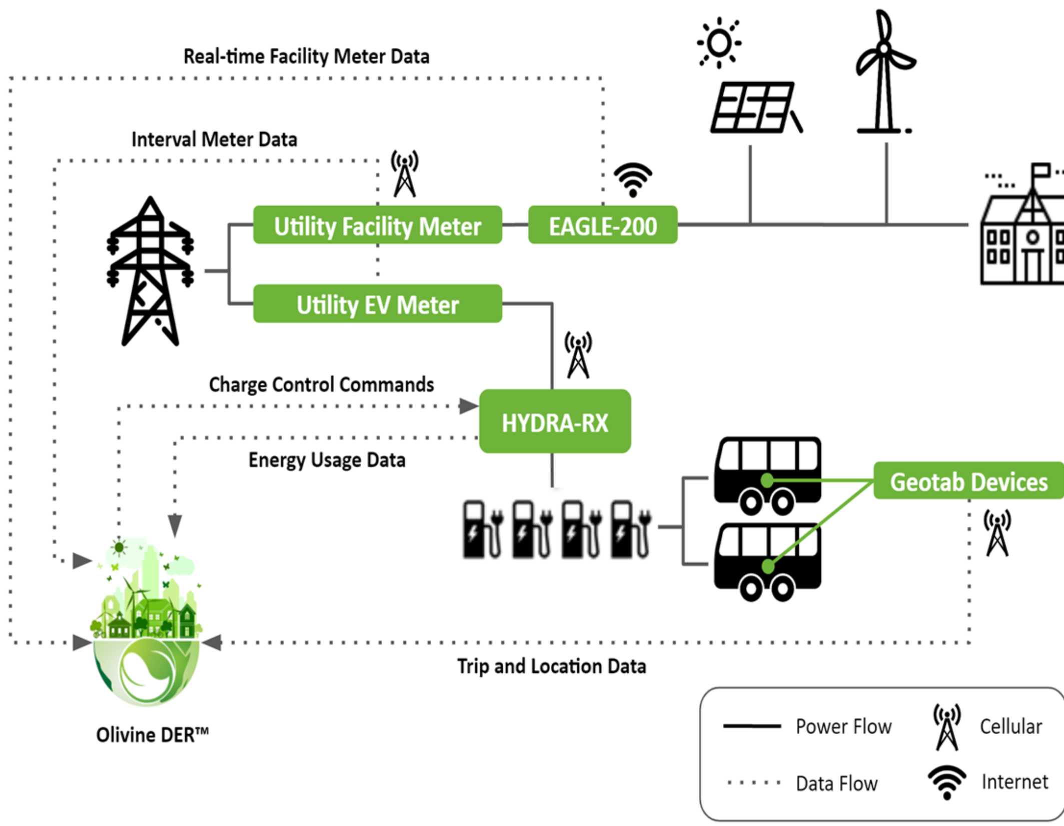

FIGURE 8 OLIVINE SYSTEM IMPLEMENTATION FOR PG&E'S PITTSBURG USD PILOT

As EV markets mature, the struggle to create stable baselines at DCFC and workplace charging stations may be naturally alleviated. However, strategies such as partnering DR with ALM, over-building capacity, and installing batteries with stations can also improve opportunities for load reduction during acute events. Partnering with ALM allows more granular control of charge patterns, and can work in conjunction with DR rather than at odds with it. Both over-building capacity and pairing batteries with charge stations can allow load reduction below normal usage during a DR event, while maintaining availability for customers.

Discussion

Bi-directional Charging and Exports

Participants expressed interest in pilots starting in 2021 or 2022 that will test bi-directional charging capabilities. The technology exists now and has been testing in various iterations over several reasons. Pilots are needed to:

- Deploy at sufficient scale to gauge customer engagement & response.
- Provide market pull for OEMs to more widely enable this technology.
- Scale bi-directional EVSE to reduce cost and create a robust and competitive market.
- Determine how to optimize stacking various VGI value streams (see the various applications listed in the VGI WG report - VGI Working Group Final Report 6.30.2020 (gridworks.org).
- Overcome any practical barriers to deploying V2G in IOU programs.

To support bi-directional charging and exports, utilities might enforce vehicle connectors that do not limit power (e.g., level 1 chargers) and support the removal of regulatory barriers for V2G AC. Exports might be incentivized as fully incremental for purposes of performance evaluation. Innovation and adoption is also necessary in the market, as many vehicles and/or chargers available today do not have bi-directional or Open ADR functionality.

Below are lists from the CEC of vehicles available or pending that are capable of High-Level Communication (HLC).

Automotive Manufacturer	DC Conductive	AC Conductive	AC Wireless
Audi ▫	**X**	**X**	**X**
BMW	**X**	**X**	**X**
Daimler ▫	**X**	**X**	**X**
Ford ▫	**X**	**X**	**X**
GM	**X**		
Hyundai-Kia ▫	**X**	**X**	**X**
Lucid ▫	**X**	**X**	
Porsche ▫	**X**	**X**	**X**
Rivian ▫	**X**	**X**	
Volvo	**X**	**X**	
Volkswagen ▫	**X**	**X**	**X**

Below are lists from the CEC of EVSE available or pending that are capable of HLC.

AC EV Supply Equipment Manufacturer
Available or Announced for U.S.
Delta: AC MAX
Elitegroup Computer Systems: LIVA
Electrify Home: HomeStation
Innogy: EVP, eStation, and eBox
Nuvve + IoTecha
Siemens: Versicharge
Next generation on a Roadmap
Enel X
EVBox
EVCA Members

Load Management Opportunities

The VGI Working Group recommended (2.17) that load management technologies could be deployed to avoid distribution upgrades, and focus capacity assessment on the Point of Common Coupling.[37] Participants noted that making assumptions about panel capacity when installing charging sites may allow automated load management (ALM) to reduce system upgrades, but it may also limit the ability to increase or decrease capacity in accordance with grid needs and signals. On the other hand, more advanced ALM solutions – for instance, technology providers that provide optimization and Open ADR – can respond more efficiently to dynamic grid demand and prices.

Furthermore, the VGI Decision requires the IOUs to "describe criteria for ALM deployment in their applications for TE programs, rules, or tariffs," and "provide customer education and evaluate customer acceptance once ALM systems are installed."[38]

[37] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group. June 30, 2020. California Public Utilities Commission DRIVE OIR Rulemaking (R.18-12-006). P 38
[38] D.20-12-029. P 29.

Customer Experience and Engagement

Workshop participants who own EVs noted several hurdles to a successful customer experience. Some popular EV models (i.e., Tesla Model 3) do not have bi-directional capability. Many popular car chargers are not yet bi-directional. And popular apps to manage EV charging have significant issues, including over-discharging the battery, requiring manual inputs from the customer, and constantly pinging the EV which drains the battery faster.

As the CEC noted, general driver engagement and range anxiety are hurdles to DR participation for EVs. "Incorporating VGI strategies into any existing [DR] program may require education for potential market participants,"[39] and technical investments can be considered by the utilities to effectively enroll and manage EV customers.

Dual Participation

Customers cannot typically participate in two market-integrated DR programs at the same time for two primary reasons: 1) CAISO does not allow double incentivizing for either capacity or energy; 2) the DRP registers the customer location with CAISO, in order to bid them into the market, and the location cannot simultaneously be registered by two DRPs. Also, as of 2018, limitations exist on dual participation between CPP and DR programs.[40]

Polls

There were four polls conducted at intervals during the workshop, to increase engagement and gather feedback in a quantifiable format. The results are summarized here. For details, see the Polls section in the Appendix.

Poll 1: How Well Do You Know Demand Response?

Most participants grasped the basics of demand response. 72% correctly identified what "PDR" stands for, and there was a general understanding that multiple technologies can respond to DR events, especially with the support of ADR. When asked "Who is the ideal DR customer?", 27% of free-text answers were "Everyone".

This poll presented an opportunity to explain to participants that DR as a concept is load agnostic. Individual DR programs may have restrictions on customers participation that favors certain load types over others, though. It was also noted that the word "program" is important when talking about DR in California. IOUs have programs, pilots, and studies, but the requirement to be market-integrated only applies to programs, which are approved in an application submitted by the IOUs every 5 years. The next DR application – for 2023-2027 – is due November 1, 2021. It was also clarified that some DR programs are only dispatched by CAISO awards, while others can be dispatched by either CAISO award or emergency grid conditions determined by either CAISO or the IOU.

[39] D.20-12-029. P 33.

[40] CPUC Decision 18-11-029, Ordering Paragraph 1.

Poll 2: What Are Your Initial Thoughts On Existing DR Programs?

It was clear that participants were both interested in demand response and found it to be complicated. DRAM, ELRP, and the two EV studies at PG&E were of particular interest. The opportunity for growth in demand response was emphasized by sharing that only about 10% of residential customers are currently enrolled in a DR program.

Poll 3: What Is Your Experience Of Barriers To Participation In DR?

Here we explored further how DR programs are constructed, and what barriers to participation are most impactful to stakeholders.

We discussed PDR as a load reduction product, in contrast to CAISO's DERP program, which allows for export but does not provide RA and excludes NEM. There is also a CAISO market model for load shift: PDR-LSR (Proxy Demand Resource-Load Shift Resource); however, it is currently only for batteries and none of the IOUs have a retail tariff for PDR-LSR at this time. It is being considered for the 2023-2027 DR Application.

Of the significant barriers provided, stakeholders ranked awareness of DR programs by EV owners/DRPs highest, with the additional barrier of technology the most common response in freetext answers.

Poll 4: Where Do We Go From Here?

Participants equally called out policy to enable export, flexibility, real time pricing (RTP), and money payment as impactful changes that could foster EV participation in DR. All respondents were interested in RTP, and on average rated the workshop 4.5/5.

Additional Suggestions and Ideas to Address Barriers

As Pasquale Romano, CEO of ChargePoint, recently noted, the approach for incentivizing EV adoption "is not one size fits all."[41] This is also true when it comes to creating opportunities for EV participation in DR. Residential charge owners, multi-unit dwelling (MUD) charge sites, public fast charging stations, and commercial fleets all have different load profiles and different charging needs. DR options might focus on addressing several high-impact EV use-cases, while not becoming so complex that the choices are unclear to customers or aggregators. Incentives need to be carefully determined to value avoided costs and load shift appropriately, value EVs on par with other DERs, and value V2G higher than V1G "based on permanent load shift logic," as well as higher potential to provide resiliency services and overall impact.[42]

[41] Ohnsman, Alan. "As ChargePoint Opens On NYSE, CEO Awaits Broad EV Push By Biden Administration." Forbes. March 1, 2021.

[42] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group. June 30, 2020. CPUC R.18-12-006. P 38.

Multiple pilots and studies are underway, planned, or proposed at the IOUs through demand response options, such as the Demand Response Emerging Technology (DRET) program, and the VGI pilots, in accordance with SB 676[43] and the VGI Decision[44]. These efforts will gather data about EV participation in DR, and the results will inform whether existing DR programs are enhanced and/or new DR programs are introduced for EV participation in the 2023-2027 DR Application. While more research and piloting will be necessary to gather cost data of VGI technologies and better understand customer responsiveness to financial incentives, stakeholders' feedback regarding barriers to EV participation in DR options is discussed further below.

Direct-enroll Options

This would allow residential customers who own an EV charger to enroll in a DR program with the utility directly. Characteristics required for success include a streamlined enrollment process, a set-it-and-forget-it construct, and sensitivity to variable customer vehicle needs. Technology partners – third-party vendors to manage the program, charge manufacturers, and/or vehicle manufacturers – are critical to supporting these success factors, as they will enable customers to have clear and consistent expectations, as well as advanced communication and EV management options.

Incentives could be a one-time incentive at enrollment, ongoing as events are called, or a combination of both; the key is to provide a value proposition to lower monthly bills or the total cost of ownership of the vehicle for the customer.

Barriers to residential, direct-enroll options may include:

1. **Range anxiety,** which could cause customers to charge even during DR events.
   Consider: Advanced control technology and customer education.
2. **Frustration and fatigue,** which could cause the customer to stop responding to DR dispatches.
   Consider**:** Customer-friendly apps that enable "set-it-and-forget-it" functionality.
3. **Variable schedules,** which could cause the customer to be away from home or otherwise require their EV during a DR event, or lead to a lack of baseline.
   Consider: Promote technology that allows the car to respond to DR signals regardless of location with owner consent, and/or by measuring load reduction against expected load at the time of the event rather than a baseline.
4. **EV metered with premises,** which could cause the demand from other household items, such as a washing machine, to negate the load reduction provided by the EV.
   Consider: Utilize technologies that enable visibility on the electricity flow from each device and provide utility grade telemetry, or by creating a holistic approach to load reduction opportunities for the customer that engage the whole home in DR events.

[43] California Senate. "Senate Bill No. 676, Chapter 484: An act to add Section 740.16 to the Public Utilities Code, relating to transportation electrification." October 2, 2019.
[44] "Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification." Decision 20-12-029, December 17, 2020. Rulemaking 18-12-006, December 21, 2020.

Aggregator Options

This would allow third-party DRPs who offer managed services for customers to participate with aggregated residential or non-residential customers. This allows the DRP to create a portfolio of customers and determine how to optimize load reduction with a balanced approach. Aggregators might also be technology providers, using load-control technologies to enhance the customer experience with a set-it-and-forget-it approach.

Barriers to aggregator options may include:

1. **Small site size,** which could make resources ineligible for participating in market programs.
   Consider: Allow smaller resources to participate that the utility then aggregates for market participation and create out-of-market options to provide incentives for responding to other types of event signals (i.e. RTP, LMR)
2. **Limited capacity,** which could limit load stability and ability to respond meaningfully to grid signals.
   Consider: Promote ALM and ADR programs and technologies to enable optimization such that demand, and potential load reduction or export, are reliably measurable.
3. **A need to serve customers,** which could result in the choice not to reduce demand during a DR event.
   Consider**:** Advanced control technology and DR options with shorter event durations.

Additional Incentives

ADR or EVSE installation incentives for residential and non-residential participants that comport with regulatory standards may be considered, which may be tied to a requirement for the customer or DRP to participate in an EV-eligible DR program for a set amount of time. As load-control technologies for EVs evolve, there could be an opportunity to create a simple enrollment experience, optimize usage with minimum impact to the customers, and provide consistent and reliable demand reduction when needed. Additionally, as recommended by the VGI Working Group and noted by workshop participants, EVSE installations could build permanent midday load to use excess renewable energy and further reduce GHG emissions.[45] Customers incentivized to install batteries for resiliency may be educated about potential DR options as well.

Barriers to ESVE or rebate options may include:

1. **Associated ADR enrollment requirements,** which require participants receiving ADR incentives to enroll in a DR rate or program will be a barrier as long as DR options are not conducive to EV participation.
   Consider: Ensure DR options have characteristics that encourage and take advantage of EV use cases, with a focus on those that are putting the most load on the grid.
2. **Existing technology,** which may already be installed with the EVSE, is not currently eligible for ADR incentives.
   Consider: Create processes to educate EVSE installers about ADR incentives so they apply prior to installation; Expand ADR incentives to include customers that commit to long-term automated load reduction with ADR technologies**.**
3. **EV charging sites separately metered,** which do not enable V2B or V2H, or use of a battery for EV charging during a DR event.
   Consider: EV charging sites included in resiliency planning, as a necessary public service and a storage solution, both separately and in conjunction with batteries and other technologies that comply with regulatory requirements.

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[45] Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group. June 30, 2020. CPUC R.18-12-006. P 40.

Summary

Possible Actions to Encourage EV Participation in DR

The table below summarizes considerations and ideas that may help overcome barriers to EV participation in DR. This is not necessarily a comprehensive list, and given the quickly evolving nature of EV vehicles and charge technologies, different or additional ideas may be needed. This table is also not meant to define next steps that the IOUs will take, given the in-process status of multiple efforts to determine appropriate pathways for EVs and DR. These efforts may conclude that DR models are not suitable solutions for EVs.

However, this table **is** meant to identify potential next steps should data gathered from pilots and studies with EVs demonstrate that DR can and should be expanded to include EV participation.

DR Barriers	Considerations	Ideas
Export	Examine DR program(s) tariff to measure and incentivize EV export	Participate in CAISO proceedings that examine energy exporting in wholesale markets (FERC Order 2222) and retail market-integrated DR programs to incorporate changes in CAISO markets
		Identify systems and process that integrate with Rule 21
Baselines	Examine DR program(s) tariff to utilize different baselines	Study different baseline methodologies with EVs participating in DR events to determine best approach
		Explore DR program(s) with the flexibility to accommodate different retail baseline methodologies for EVs (i.e. CBP)
		Look into DR program(s) with an alternative retail baseline methodology better suited to EV use-cases that comport with regulatory standards[46]
	Consider submetering	Examine pathway for applicable use-cases
	Accelerate EV and EV-charge adoption	See "Engagement with Market Actors" Barrier in this table
		See "Additional incentives" Barrier in this table

[46] Per CAISO, alternative retail baselines may be used if approved by CAISO and conforming to the North American Energy Standards Board (NAESB) standards.

TOU participation from 4-9pm	Research EV export in a DR program(s)	See “Export” Barrier in this table
	Explore additional incentives with a DR option(s)	See “Additional incentives” Barrier in this table
	Examine new baseline options to measure performance during a DR event	See “DR baselines” Barrier in this table
Event durations (4 hour min)	Study DR options to allow participation for less than 4 hours	Investigate EV customer combinations or strategies that can reduce load for 4 hours in aggregate
		Explore DR options for EVs that do not require 4 hour duration (e.g. ELRP)
		Consider options for EVs that are out-of-market (i.e. not PDR) for short-duration response (e.g. RTP; LMR option)
Minimum PDR load reduction (100kw)	Examine DR program(s) tariff to allow EV aggregations <100 kW	SDG&E currently allows <100 kW aggregations for CBP
		PG&E is testing minimum 25 kW aggregations for CBP in 2021-2022
		Identify and promote DR options for EVs that are out-of-market (i.e. not PDR) for direct-enroll or small aggregations (e.g. CPP rates)
		Propose new options for EVs that are out-of-market (i.e. not PDR) for direct-enroll or small aggregations (e.g. residential ADR incentives; LMR option)
Engagement with Market Actors	Create ongoing opportunities for collaboration	Offer public presentations to inform customers, market actors, and other stakeholders about DR options for EVs
Customer Education	Create marketing materials and community outreach opportunities	Create process with EVCN (PG&E) participants to enroll in DR
		Educate Rule 21 EV customers about DR options
		Offer public presentations to inform customers, market actors, and other stakeholders about DR options for EVs
Export	Examine DR program(s) tariff to measure and incentivize EV export	Participate in CAISO proceedings that examine energy exporting in wholesale markets (FERC Order 2222) and retail

		market-integrated DR programs to incorporate changes in CAISO markets
		Identify systems and process that integrate with Rule 21
Additional incentives	Examine DR options for EVs in conjunction with other incentives or programs	Look into ADR incentives for residential EV customers
		If available, educate non-residential EV customers about existing ADR incentives
		Consider ADR incentives for EVCN and VGI Pilot participants
		Inform customers receiving rebates for battery storage about EV incentives and DR options
		See "Customer Education" Barrier in this table

Appendix

OIR 20-11-003 (Summer Reliability)

Final Decision: **https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=373745051**

Attachment 1: **https://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=373973362**

Published Reports and Resources

California Energy Commission (CEC)

CEC. "Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030." January 2021.

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California Independent System Operator (CAISO)

"Proxy Demand Resource (PDR) & Reliability Demand Response Resource (RDRR) Participation Overview."

"Demand response – proxy demand resource."

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"System Emergency." Operating Procedure: 4420. October 31, 2019.

"Demand Response Customer Partnership Working Group." April 22, 2021.

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Madrigal, Radha. "Overview of Reliability Demand Response Resource." May 8, 2014.

Madrigal, Radha. "Energy Storage and Distributed Energy Resources (ESDER) Phase 3B." June 22, 2020.

California Public Utilities Commission (CPUC)

"Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification." Decision 20-12-029, December 17, 2020. Rulemaking 18-12-006, December 21, 2020.

"Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Reliable Electric Service in California in the Event of an Extreme Weather Event in 2021." (Summer Reliability OIR.) Decision 21-03-056, March 25, 2021. Rulemaking 20-11-003, March 26, 2021.

"Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements." Decision 14-03-026, March 27, 2014. Rulemaking 13-09-011, September 19, 2013.

"Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements." Decision 14-12-024, December 4, 2014. Rulemaking 13-09-011, September 19, 2013.

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"Application of Pacific Gas and Electric Company (U39E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022." Decision 18-11-029, November 29, 2018. Application 17-01-012, December 10, 2018.

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"Capacity Valuation for BTM Hybrid Resources Workshop." November 24, 2020.

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Kaneshiro, Bruce. "Baselines for Retail Demand Response Programs." March 12, 2009.

Other

Alstone, Peter, et al. "Demand Response Potential for California SubLAPs and Local Capacity Planning Areas: An Addendum to the 2025 California Demand Response Potential Study." April 1, 2017.

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VGI-DR Workshop Agenda

Agenda Summary

In this workshop, the three California IOUs – SCE, SDG&E, and PG&E – will present on opportunities for VGI providers to participate in demand response programs. In addition to identifying ways that EVs can participate in existing DR programs, workshop participants will be asked to identify barriers to EVs participating in DR programs and potential solutions; this feedback will be compiled and published in a report within 30 days of this workshop (D.20-12-029).

Agenda Items

1:00pm – 1:05pm	Safety
1:05pm – 1:10pm	Presenters and Purpose of Workshop
1:10pm – 1:15pm	*Poll: How well do you know DR?*
1:15pm- – 1:45pm	EV-Eligible DR Programs
1:45pm – 1:50pm	*Poll: What are Your Initial thoughts on existing DR opportunities?*
1:50pm – 2:00pm	*** 10 min Break ***
2:00pm – 2:30pm	Challenges and Barriers for EVs in DR
2:30pm – 2:35pm	*Poll: What is Your Experience of Barriers to EV Participation in DR?*
2:35pm – 2:45pm	*** 10 min Break ***
2:45pm – 3:15pm	Lessons Learned
3:15pm – 3:45pm	Stakeholder Discussion
3:45pm – 3:55pm	*Poll: Where Do We Go From Here?*
3:55pm – 4:00pm	Wrap-up and contact information

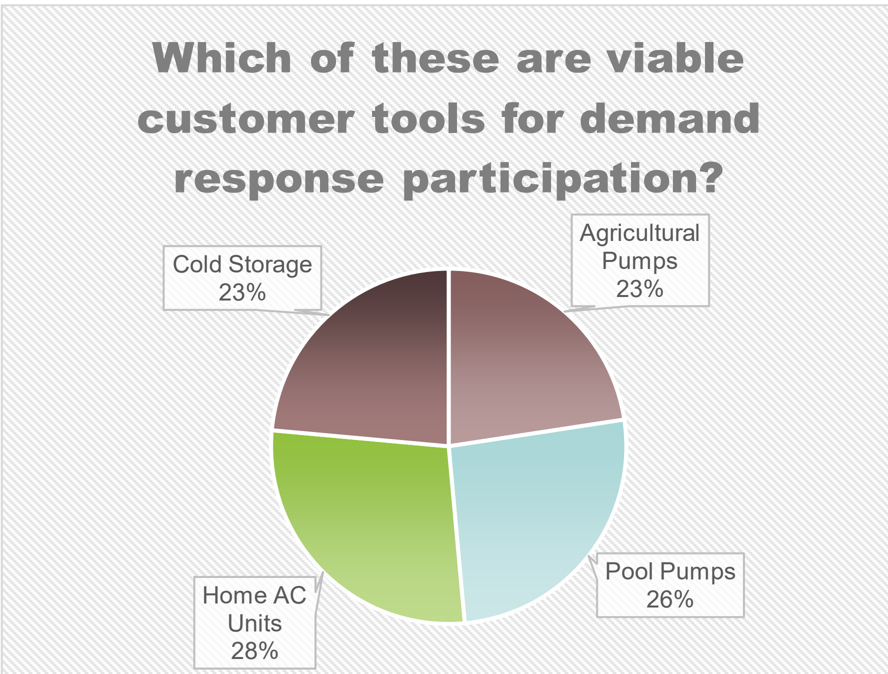
Presenters

Ed Pike	CPUC, Energy Division
Nicolette Sowa	PG&E
Carl Besaw	SCE
Brad Mantz	SDG&E
Adam Langston	BMW
Noel Crisostomo	CEC
Abby Shelton	Olivine
Marc Monbouquette	Enel X

Polls

The following are the results from the polls conducted at the workshop to increase engagement and gather feedback in a quantifiable format.

Poll 1: How Well Do You Know Demand Response

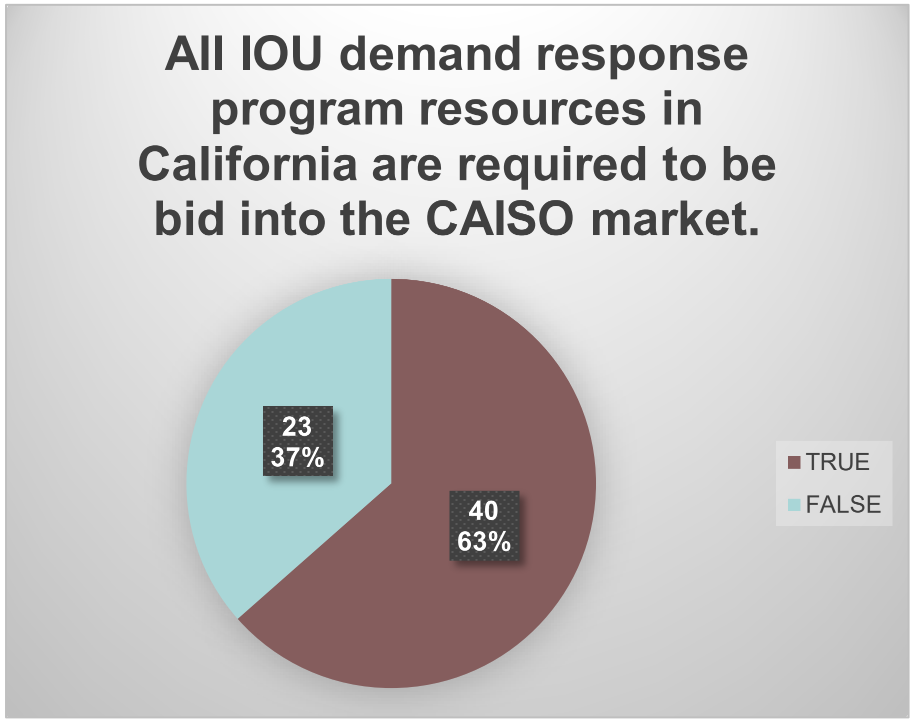


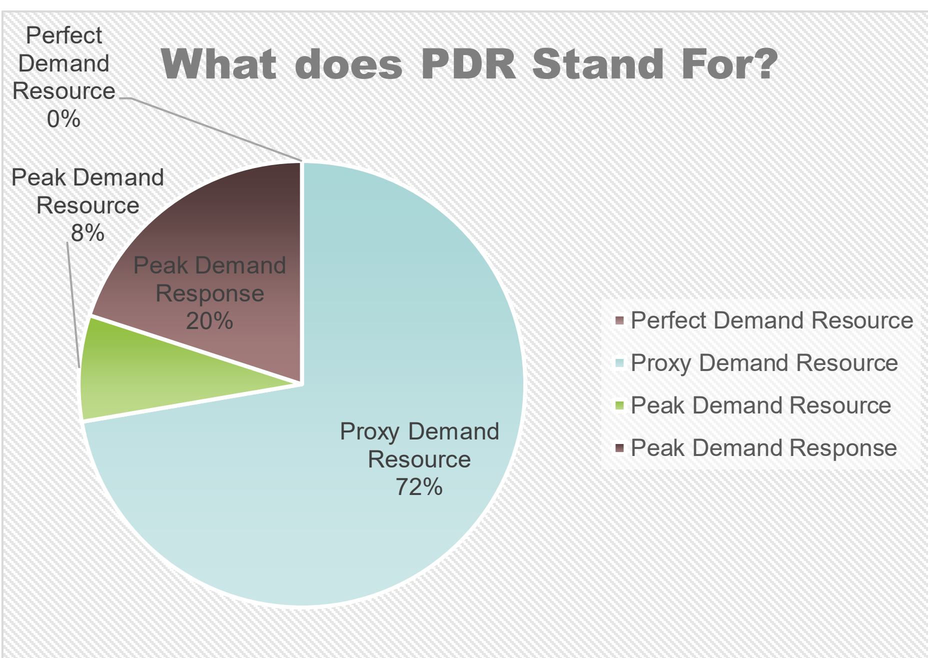
All answers are correct.

DR as a concept is load and technology agnostic. However, individual DR programs may have restrictions on customer participations that favor certain load over others.

Correct Answer: TRUE

The word “program” is important here; the IOUs have programs, pilots, and studies. The market-integration requirement only applies to programs, which are approved in an application submitted by the IOUs every 5 years. The next DR application – for 2023-2027 – is due November 1, 2021.



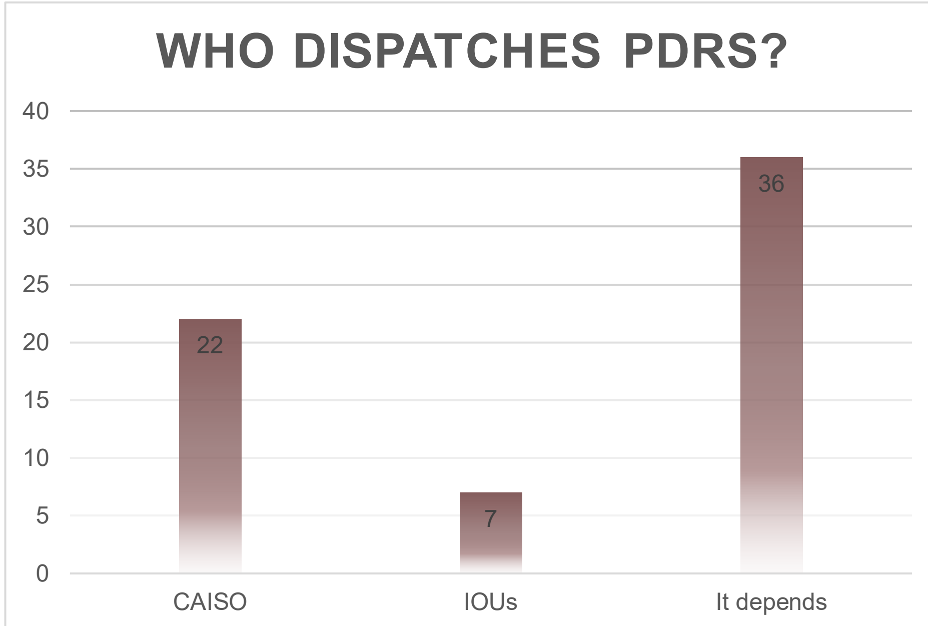


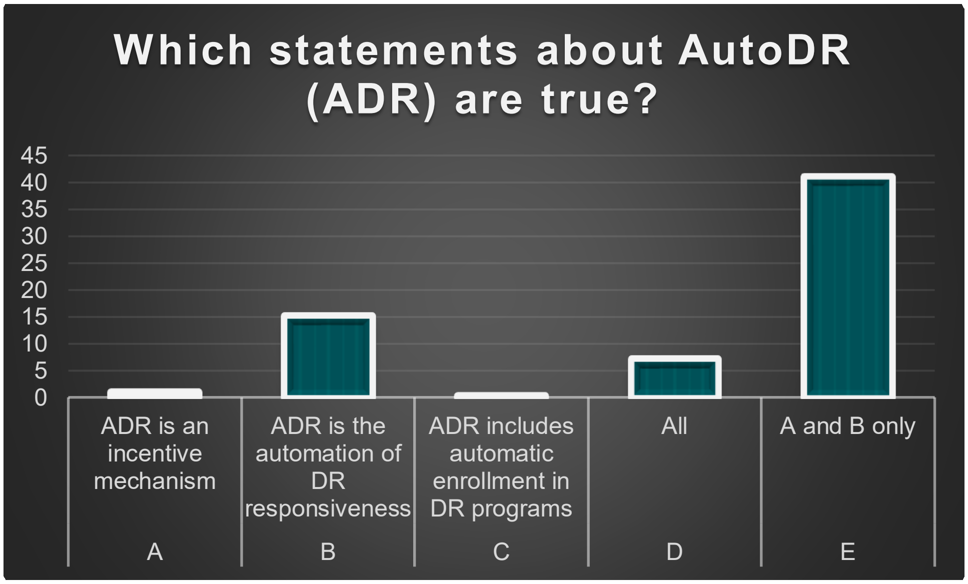
Correct answer: Proxy Demand Resource

“Proxy” for spinning and non-spinning, as well as residual unit commitment, reserves.

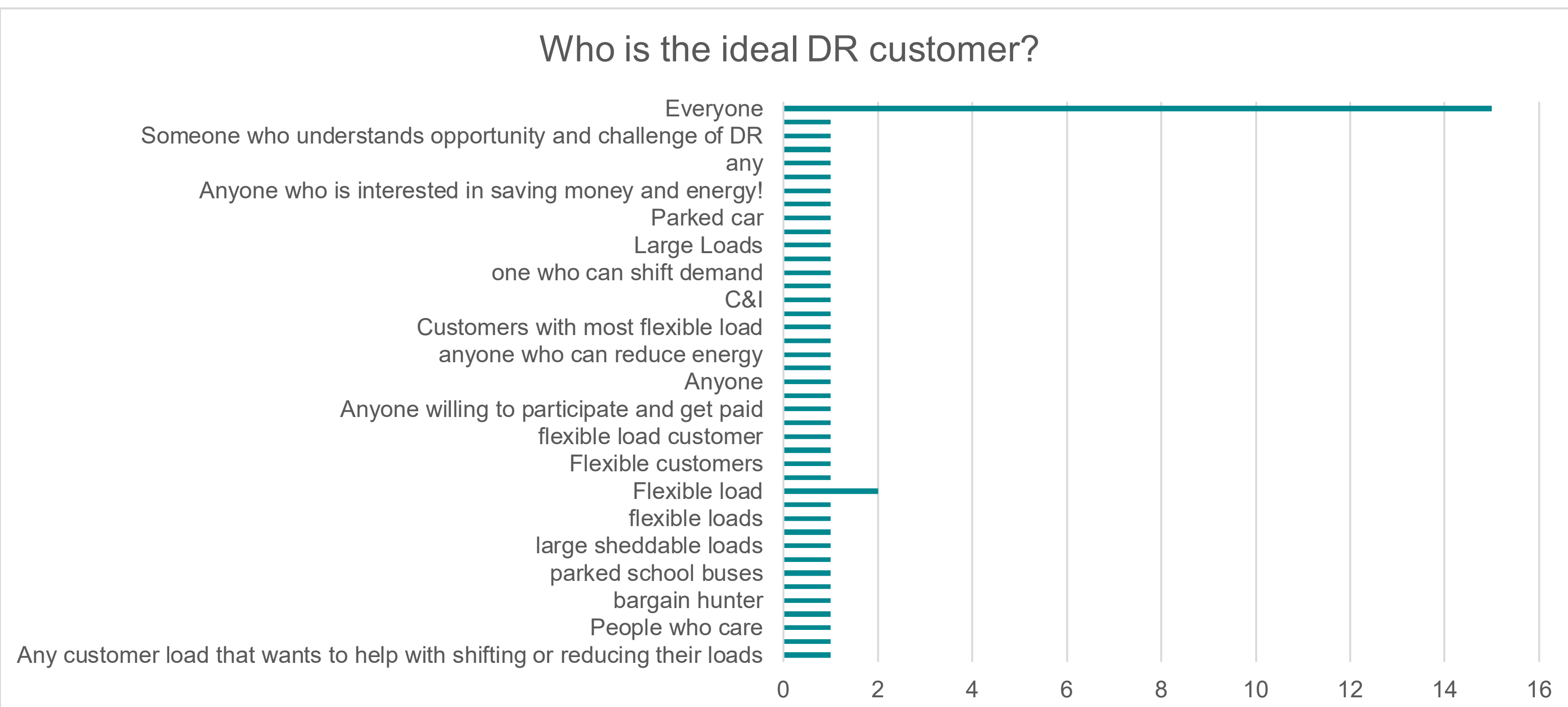
Correct answer: It depends

Some DR programs are only dispatched by CAISO awards, others can be dispatched by either CAISO award or emergency grid conditions determined by either CAISO or the IOU.

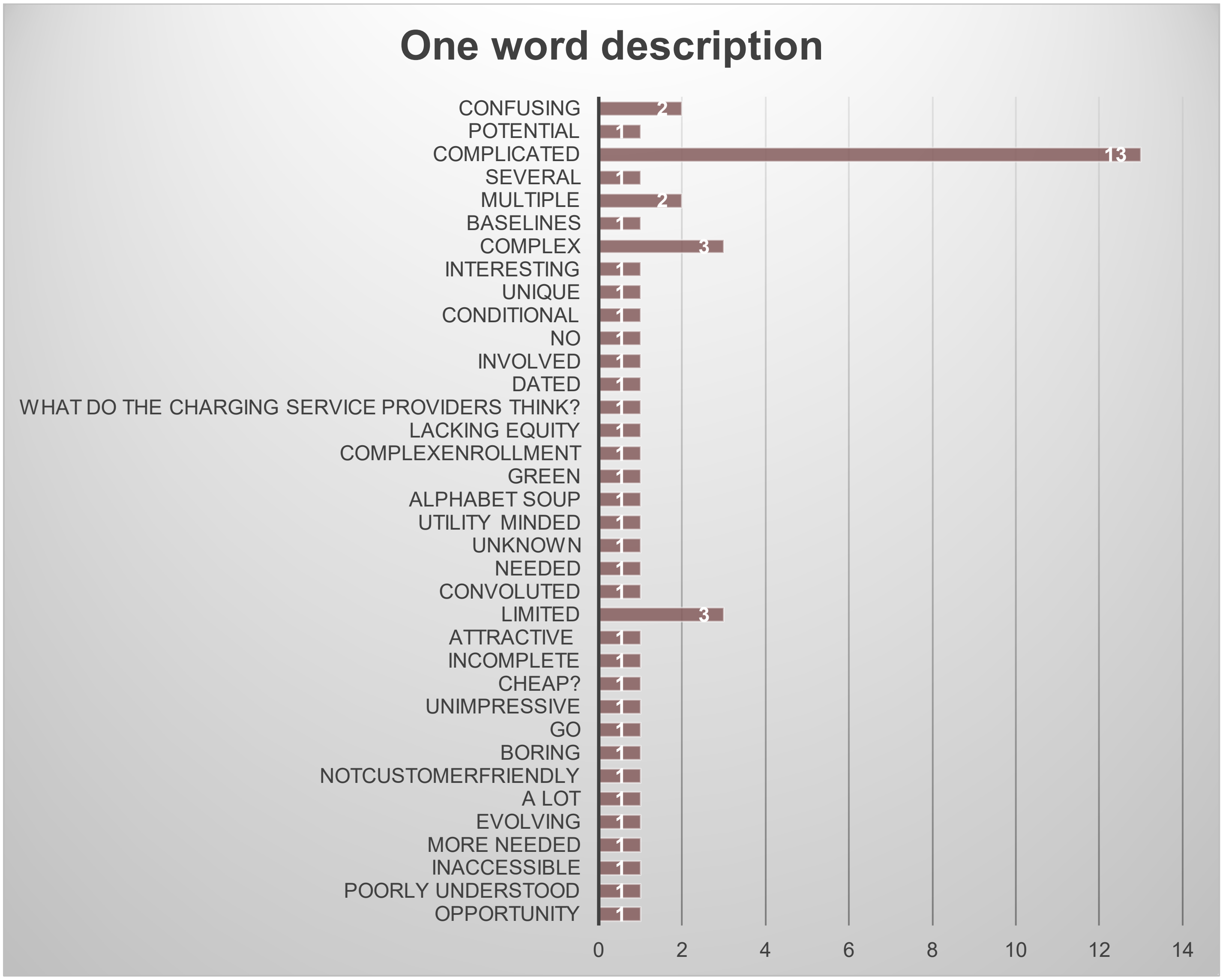


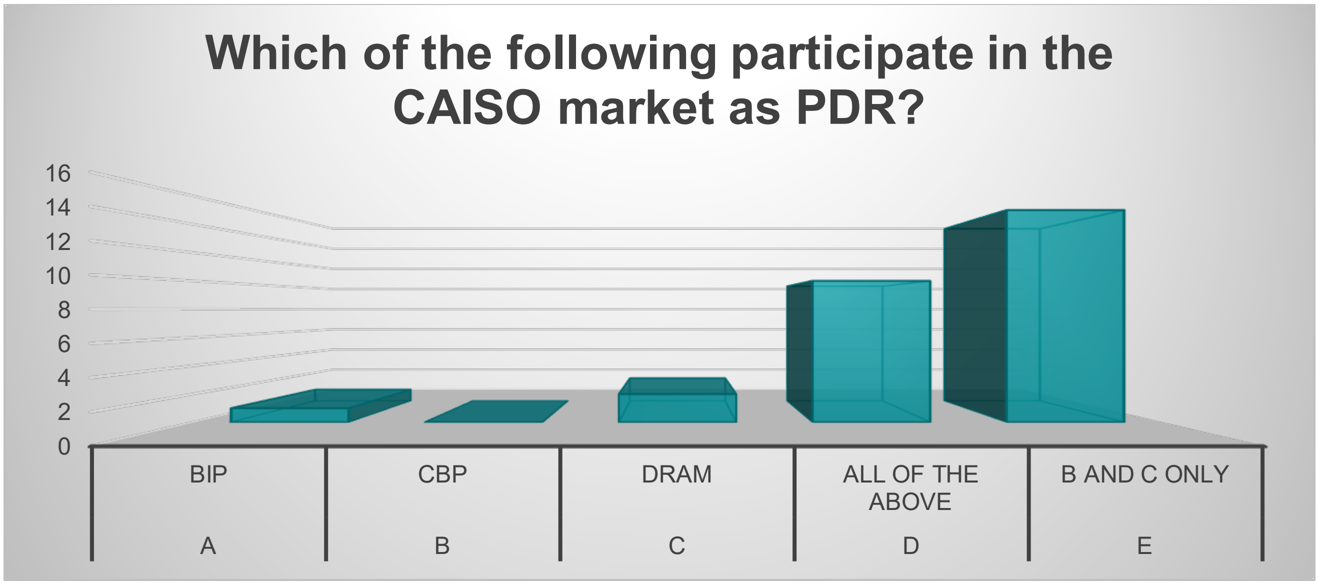


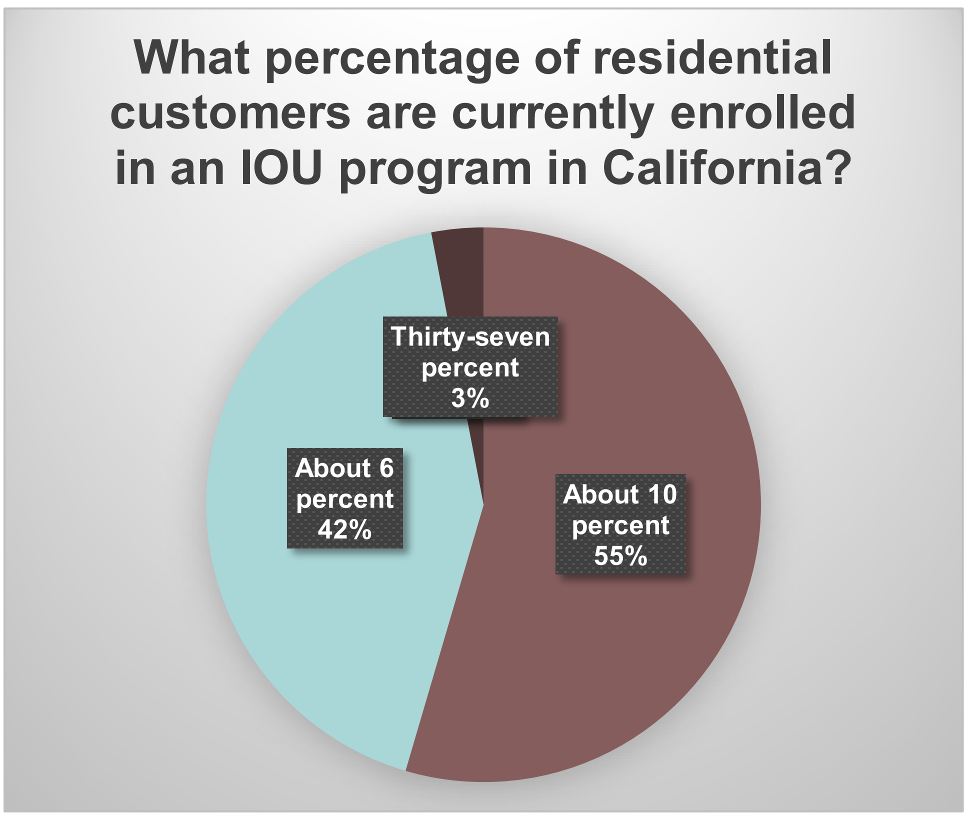
Correct answer: A and B only



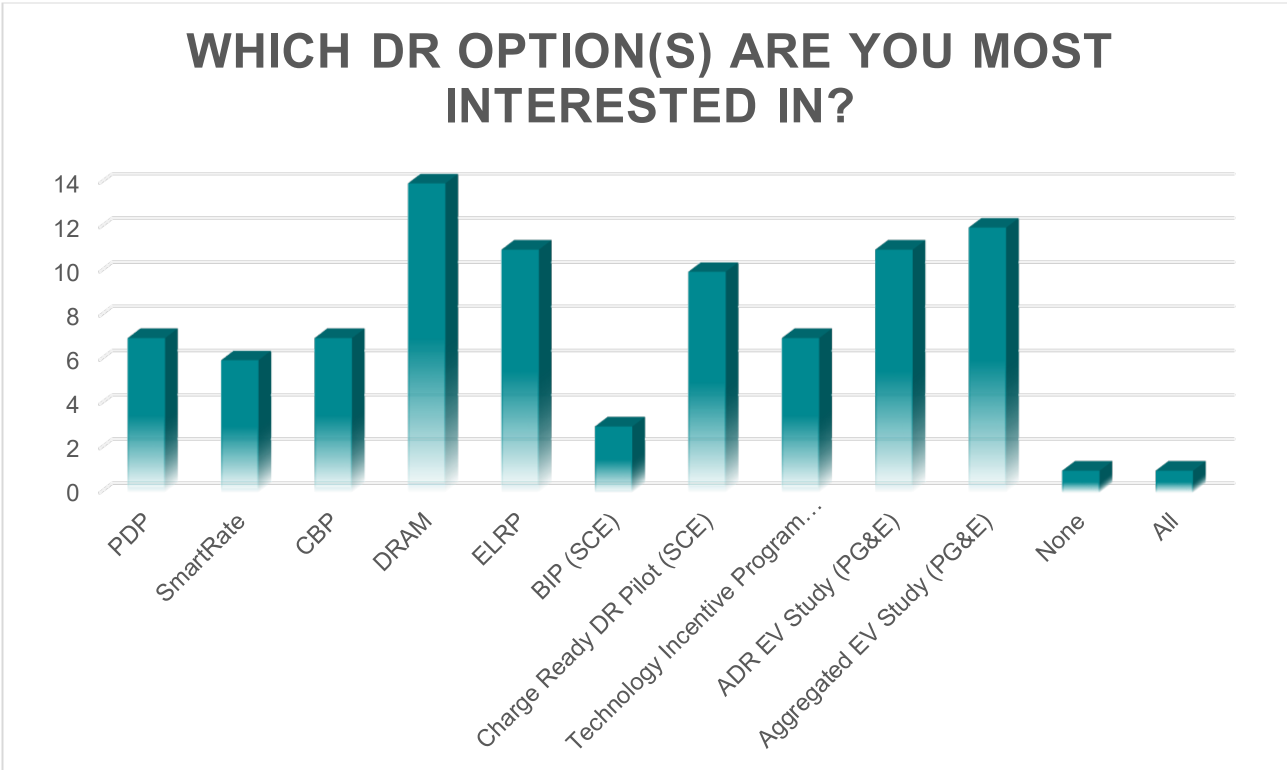
Poll 2: What Are Your Initial Thoughts on Existing DR Programs

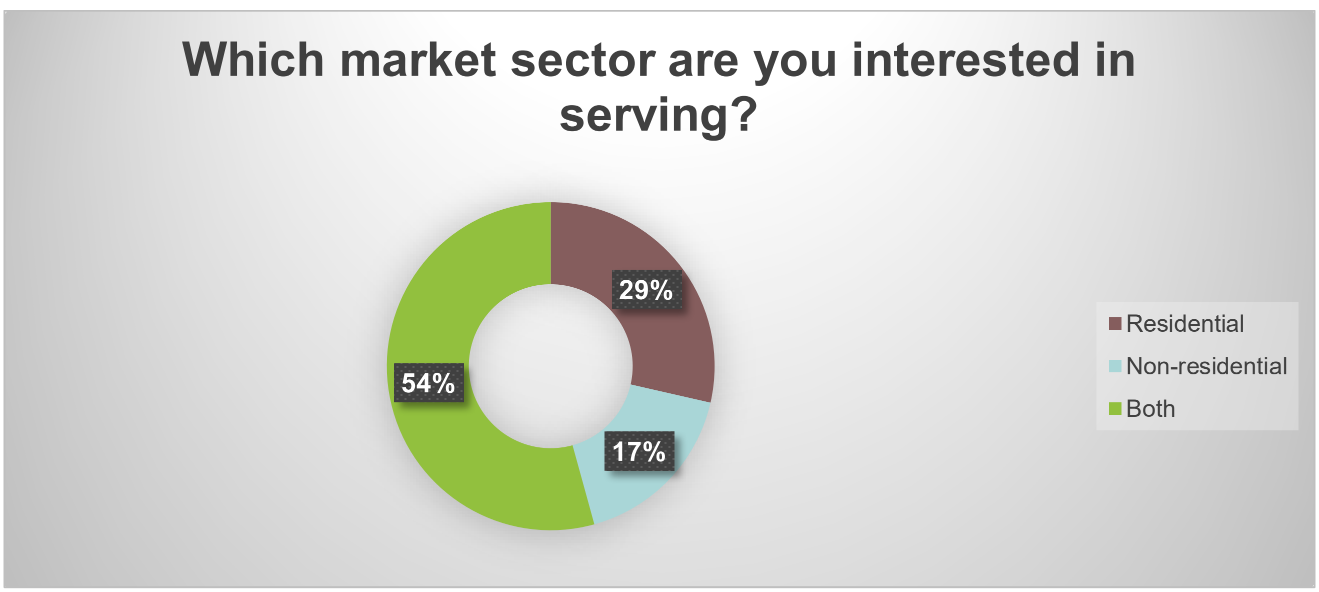




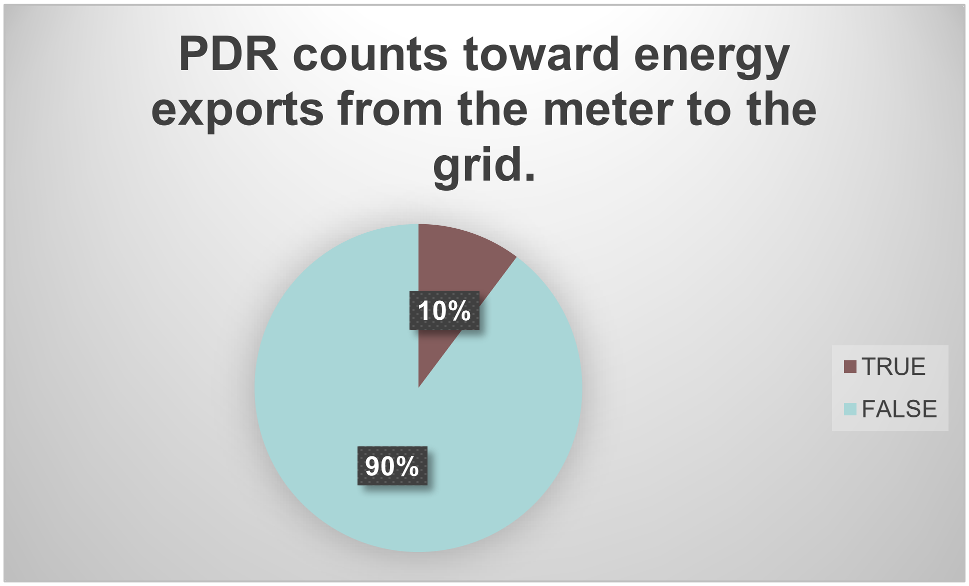


Correct answer:
About 10 percent


WHICH DR OPTION(S) ARE YOU MOST INTERESTED IN?
14
12
10
8
6
4
2
0
PDP
SmartRate
CBP
DRAM
ELRP
BIP (SCE)
Charge Ready DR Pilot (SCE)
Technology Incentive Program...
ADR EV Study (PG&E)
Aggregated EV Study (PG&E)
None
All


Which market sector are you interested in serving?
29%
17%
54%
Residential
Non-residential
Both

Poll 3: What is Your Experience of Barriers to EV Participation in DR?

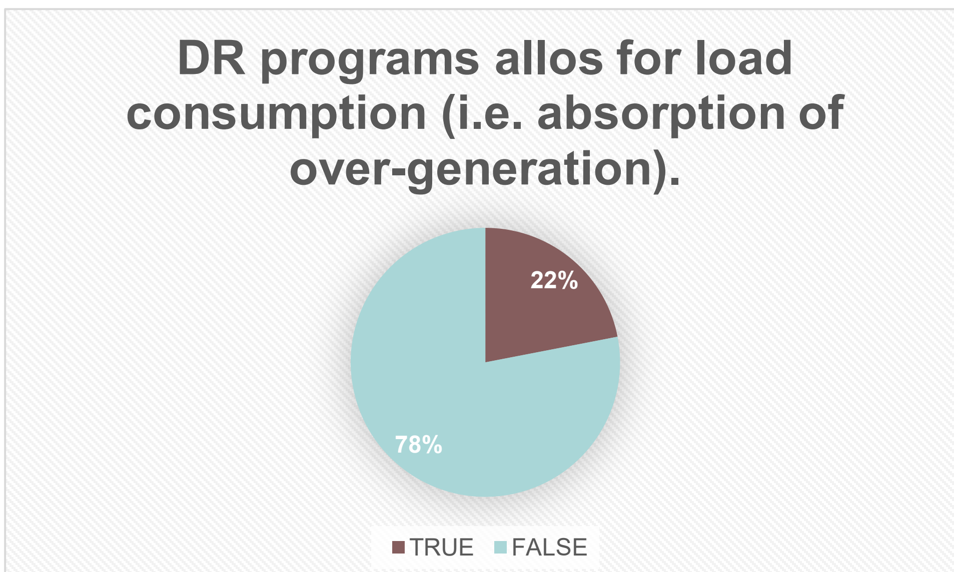


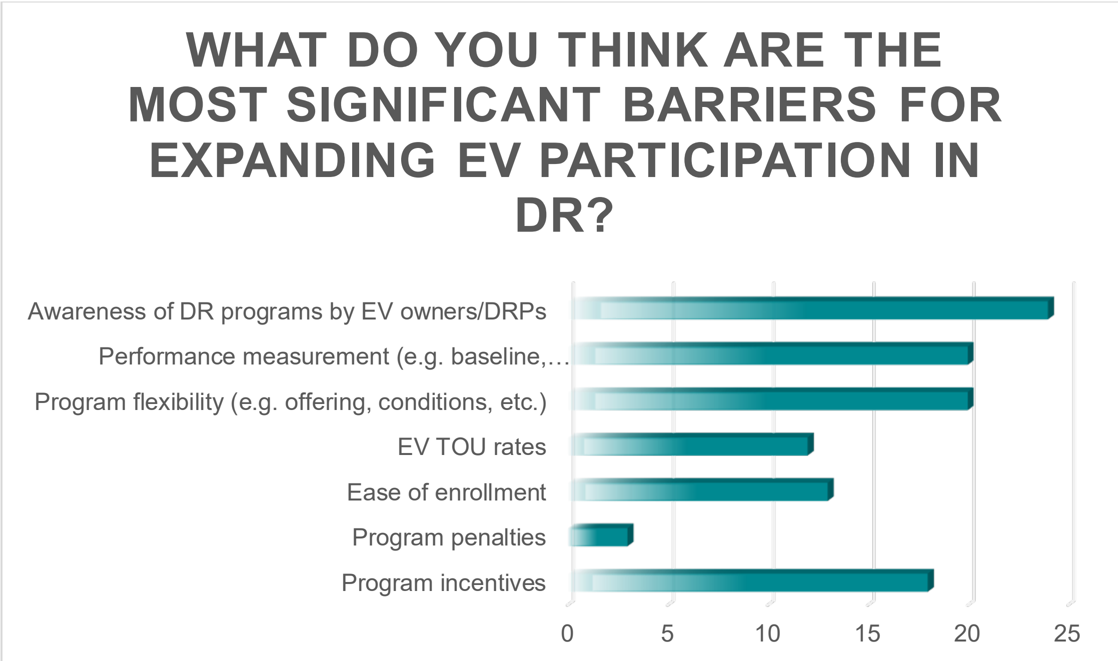
Correct answer: FALSE

PDR is a load reduction product. In contract, CAISO has a program – Distributed Energy Resource Provider (DERP) – that allows for export but does not provide RA and excludes NEM.

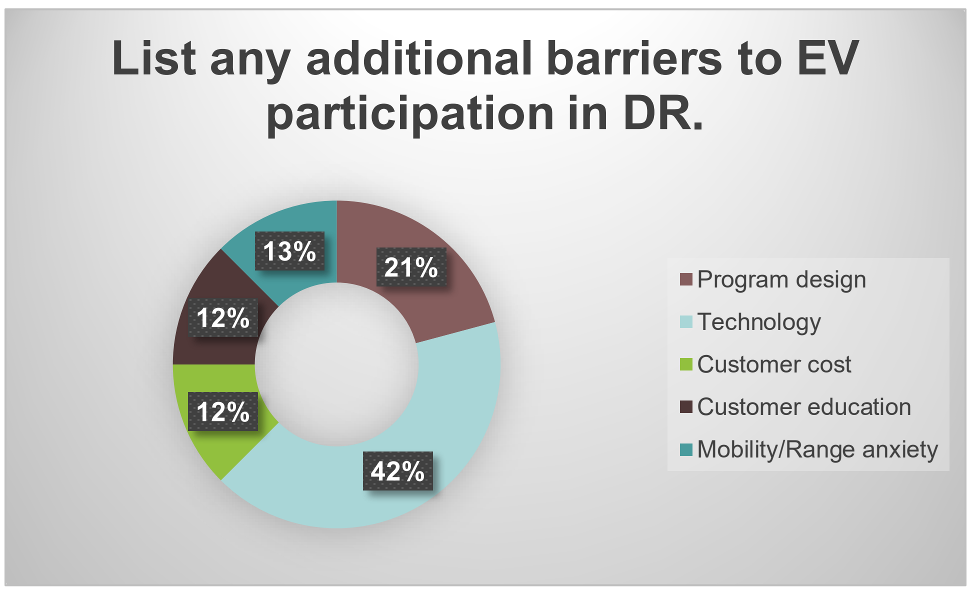
Correct answer: FALSE

PDR-LSR (Proxy Demand Resource-Load Shift Resource) is a CAISO market model for load shift. However, it is currently only for batteries and none of the IOUs have a retail tariff for PDR-LSR at this time. It is being considered for the 2023-2027 DR application.





Note: Participant answers were grouped by like category to more impactfully represent the barrier.



Acronyms

AC	Alternating Current	**ADR**	Automated Demand Response
ALM	Automated Load Management	**A/C**	Air Conditioner
A/S	Ancillary Services	**BEV**	Battery Powered Electric Vehicles
BIP	Base Interruptible Program	**B2B2B**	Business-To-Business-To-Business
B2B2C	Business-To-Business-To-Consumer	**B2C**	Business-To-Consumer
BMS	Bus Battery Management System	**BTM**	Behind-The-Meter
C&I	Commercial & Industrial	**CAISO**	California Independent System Operator
CBP	Capacity Bidding Program	**CCA**	Community Choice Aggregator
CEC	California Energy Commission	**CPP**	Critical Peak Pricing
CPUC	California Public Utilities Commission	**DA**	Day-Ahead
DC	Direct Current	**DCFC**	Direct Current Fast Charger
DCM	Data Communication Module	**DER**	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System	**DERP**	Distributed Energy Resource Provider
DG	Distributed Generation	**DIDF**	Distribution Investment Deferral Framework
DO	Day-Of	**DR**	Demand Response
DRAM	Demand Response Auction Mechanism Pilot	**DRP**	Demand Response Provider
ED	Energy Division (CPUC)	**ELRP**	Emergency Load Reduction Pilot
EMS	Energy Management System	**EREV**	Extended Range Electric Vehicle
EV	Electric Vehicle	**EVSE**	Electric Vehicle Supply Equipment
EVSP	Electric Vehicle Service Provider	**FERC**	Federal Energy Regulatory Commission
FSL	Firm Service Level	**GHG**	Greenhouse Gas
HLC	High-Level Communication	**IEC**	International Electrotechnical Commission
IEPR	Integrated Energy Policy Report	**ILP**	Interruptible Load and Demand Response Programs
ILR	Incremental Load Reduction	**IOU**	Investor-Owned Utility
kW	Kilowatt	**kWh**	Kilowatt-Hour
LBNL	Lawrence Berkeley National Laboratory	**LCR**	Load Capacity Requirement
LDEV	Light-Duty Electric Vehicles	**LIP**	Load Impact Protocols
LSE	Load-Serving Entity	**LSR**	Load Shifting Resource
MGO	Meter Generator Output	**MHDEV or M/HD**	Medium- and Heavy-Duty Electric Vehicles
MOO	Must-Offer Obligation	**MW**	Megawatt

NEM	Net Energy Metering	**NIST**	National Institute of Standards and Technology
NREL	National Renewable Energy Laboratory	**OEM**	Original Equipment Manufacturer
OIR	Order Instituting Rulemaking	**PD**	Proposed Decision
PDP	Peak-Day Pricing	**PDR**	Proxy Demand Resource
PG&E	Pacific Gas & Electric Company (IOU)	**PHEV**	Plug-In Hybrid Electric Vehicle
PLS	Permanent Load Shift	**PTR**	Peak Time Rebate
PV	Photovoltaic	**Q&A**	Question & Answer
RA	Resource Adequacy	**RDRR**	Reliability Demand Response Resource
RFO	Request For Offer	**RTP**	Real-Time Pricing
SAID	Service Agreement Identifier	**SCE**	Southern California Edison Company (IOU)
SDG&E	San Diego Gas & Electric Company (IOU)	**SOC**	State-Of-Charge
SSDR	Supply Side Demand Response	**T&D**	Transmission & Distribution
TBD	To Be Determined	**TCO**	Total Cost Of Ownership
TE	Transportation Electrification	**TI**	Technology Incentive Program
TOU	Time-Of-Use	**VGI**	Vehicle-Grid Integration
V1G	Vehicle-To-Grid Smart Charging	**V2G**	Vehicle-To-Grid Bi-Directional Charging
V2H	Vehicle-To-Home	**XSP**	Excess Supply Pilot