California’s Virtual Power Potential:
How Five Consumer Technologies Could Improve the State’s Energy Affordability

PREPARED BY

Ryan Hledik
Kate Peters
Sophie Edelman

PREPARED FOR

GridLab

UNFORMATTED DRAFT FOR REVIEW
NOT FOR CIRCULATION OR CITATION

VOLUME I: SUMMARY REPORT
MARCH 26, 2024

Brattle

Notice

This report was prepared by The Brattle Group for GridLab. It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

We would like to thank Ric O'Connell of GridLab for the invaluable project management and insights he provided throughout the development of this report. We also are grateful for review of a draft of this study by experts at the following organizations:

- Ava Community Energy (Feliz Ventura)
- Google (Rizwan Naveed)
- OhmConnect (Cliff Staton)
- Recurve (Brian Gerke)
- Swell (Sarah Delisle, Jon Fortune)

Table of Contents

Volume I: Summary Report

Volume II: Technical Appendix

Describes all modeling and data sources

I. Summary

California's growing need for affordable capacity

California needs new low-cost generation capacity. Virtual power plants can help.

A growing problem: California has narrowly avoided significant blackouts due to shortages in power supply on multiple occasions over the past few years. Factors contributing to this challenge include increasingly extreme weather events, dependence on intermittent forms of generation, reduced flexibility of hydro systems, and reduced availability of imports from neighboring regions. Further, large-scale resources are not being connected to the grid at a pace that keeps up with demand. The cost of resource adequacy has doubled since 2017.

A real solution: California consumers are adopting clean, flexible technologies such as smart thermostats, electric vehicles, and batteries at a rapid rate. Virtual power plants (VPPs) combine these technologies across participating customers to create a resource that can reduce, shift, or generate electricity when needed. By providing these services to the power system, VPPs can make significant contributions to grid reliability while directly compensating those consumers who participate.

Estimating VPP potential: The purpose of our study is to estimate the market potential for VPP deployment in California. We define "market potential" as all cost-effective VPP capacity that can be developed at achievable, voluntary participation rates by the year 2035. We focus on five commercially available dispatchable technologies: smart thermostat-based air-conditioning control, behind-the-meter batteries, residential electric vehicle charging, grid-interactive water heating, and automated demand response for large commercial buildings and industrial facilities.

A study grounded in reality: Our market potential estimates are based exclusively on commercially-available technologies, demonstrated load impacts, and observed customer participation rates across similar program offerings in California and other jurisdictions. Estimates of VPP value account for operational limitations needed to maintain participant comfort and are tailored to public data on California's market conditions and power system costs.

California's VPP market potential

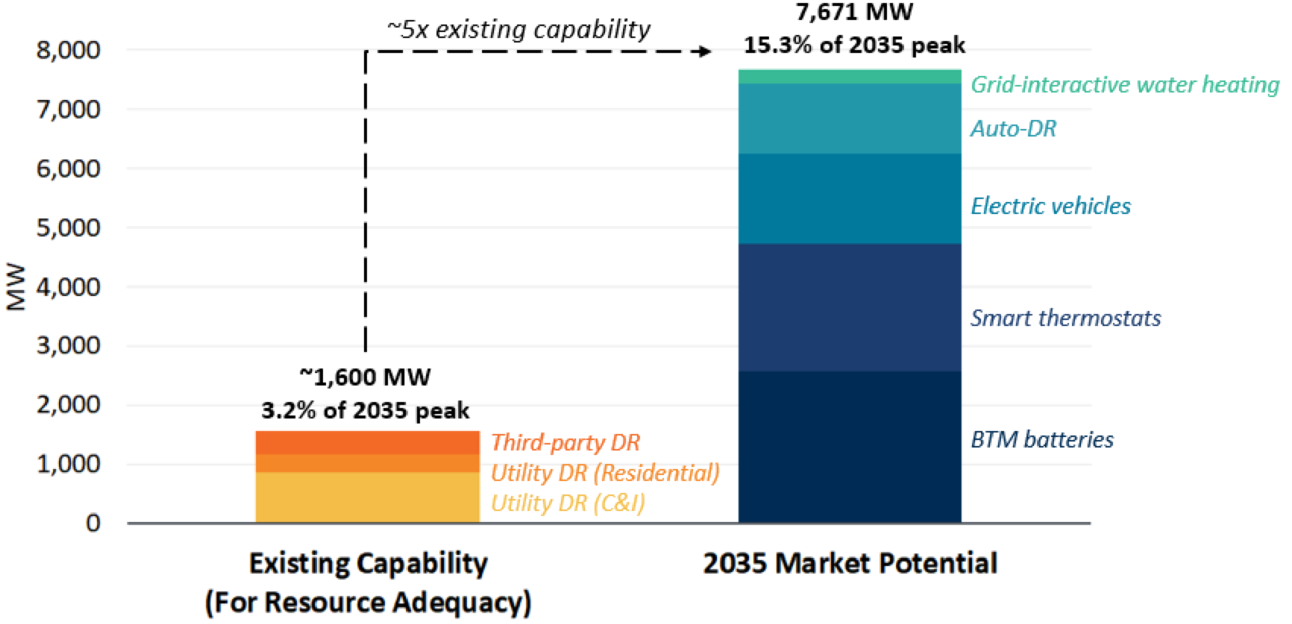
By 2035, California's VPP potential will exceed 15% of peak demand. That's 5x the existing capability.

Large potential: More than 7,500 MW of VPP capacity could be deployed cost-effectively across the state over roughly the next decade. That's significantly larger than the capacity of any single power plant in California, and higher than the total system peak demand of Los Angeles.

Resource diversity: All five VPP technologies considered in our study make material contributions to the total potential. This technological diversity is a benefit of VPPs – if adoption of one technology lags behind expectations, accelerated adoption of a different technology could offset the impact.

Additional opportunities: The inclusion of additional VPP technologies would increase the potential estimate. For example, vehicle-to-grid capability could advance to the point of commercial deployment over the next decade, which would dramatically increase the contribution of EVs to the total. Standalone energy efficiency programs, while outside the scope of our study, also could significantly increase the potential estimate if targeting savings during peak hours. Thermal energy storage, behavioral DR, and managed EV fleet charging are other potential sources of "virtual" capacity.

2035 California Statewide VPP Market Potential



Note: VPP capacity is presented as a percentage of maximum system peak demand during the resource adequacy window of 6 to 11 pm (March-July) and 5 to 10 pm (Other).

The economics of VPPs in California

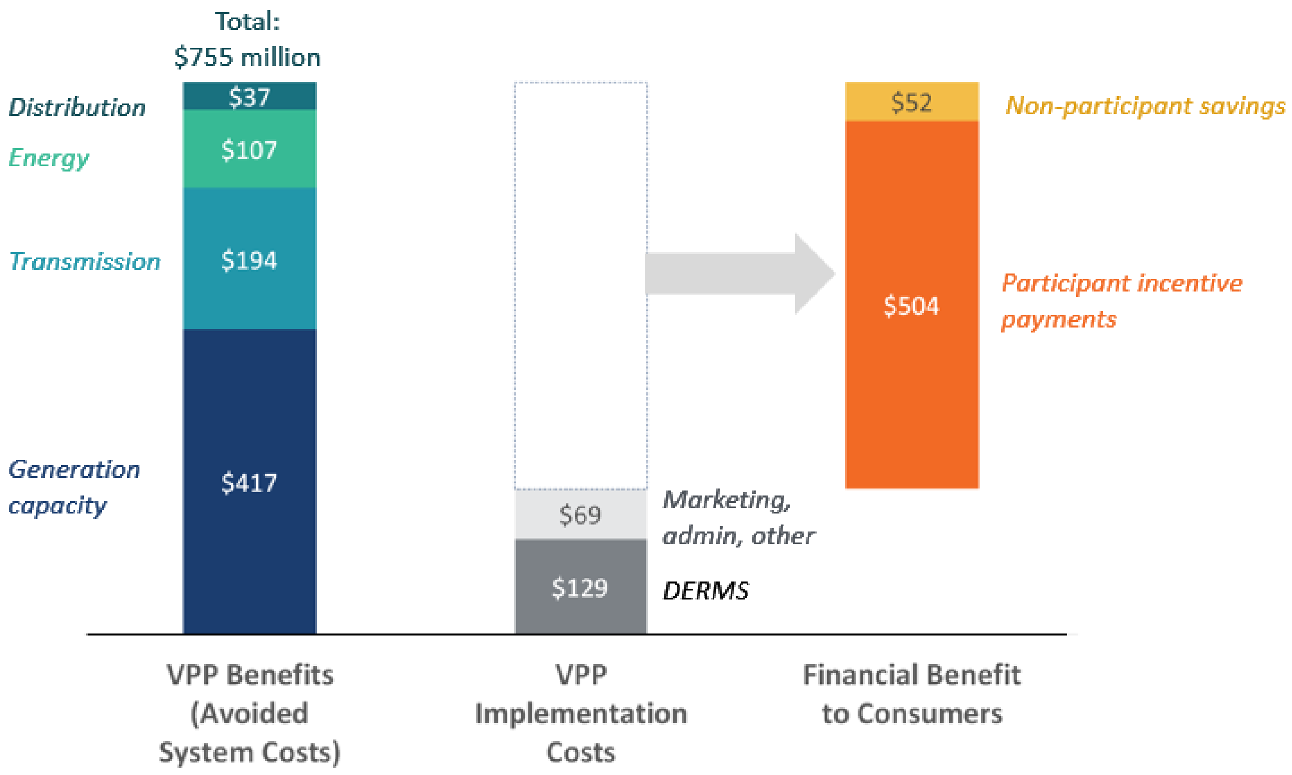
VPPs could create consumer savings of $550 million per year in California.

Significant savings: By 2035, the full statewide portfolio of VPPs could avoid over $750 million per year in traditional power system costs. That means a reduced need for new power plants and fewer required upgrades for poles and wires.

An opportunity for consumers: The majority of VPP costs will be in the form of participant incentive payments. Roughly $500 million/year would be paid directly back to those consumers who are pitching in to help keep the lights on. In fact, an individual household participating in all four residential VPP options considered in this study potentially could receive participation payments of $500 to $1,000 per year. Further, the overall cost of the VPP will be lower than alternative power supply options. The resulting net cost savings for all ratepayers - including non-participants – will provide important equity and affordability benefits.

Additional benefits: In addition to the benefits quantified in this study, VPPs will reduce risks associated with interconnection delays – they can be "built" essentially as quickly as customers adopt technologies and enroll. Further, VPPs can scale flexibly as demand grows, mitigating risks due to unprecedented uncertainty in electricity demand forecasts.

2035 Benefits and Costs of Statewide VPP Market Potential ($ Millions)



Note: Values shown in 2023 dollars. Split between participant incentives and non-participant savings will vary depending on program design.

Achieving California's VPP potential

New state policies could facilitate VPP deployment at the scale presented in this study.

Achieving California's VPP potential depends on reaching high but achievable levels of technology adoption and enrollment. Where VPP deployment barriers have been overcome in other jurisdictions, enrollment has reached or exceeded the participation rates assumed in this study (see sidebar at right).

Among many possible solutions to advancing VPP deployment, statewide policy goals or requirements could drive growth. California already has a 7,000 MW load shifting goal, as well as load management standards that could facilitate VPP uptake. New draft legislation effectively could establish the equivalent of a renewable portfolio standard for VPPs across the state.

California would not be alone in establishing such a VPP requirement. States such as Maryland, Massachusetts, Minnesota, and Oregon have shown that policy requirements can be highly impactful. If California moves forward with new VPP-focused policies, the findings of this study can help to facilitate the success of the planning, program design, and policy development activities that will follow.

Success at Scale in Other Jurisdictions

Offerings in other jurisdictions prove that successful programs can reach high levels of enrollment:

- **Smart thermostats:** In Minnesota, Xcel Energy has enrolled more than half of all eligible residential customers in A/C load control on a voluntary basis.
- **Batteries:** Green Mountain Power already has enrolled roughly 1% of its residential customer base in its battery program and forecasts that the program will reach between 4% and 8% participation by 2030.
- **Electric vehicles:** Some utilities have exceeded 40% participation in voluntary EV TOU rates. Startup company ev.energy has enrolled more than 150,000 EVs in managed charging programs across 40 utilities globally.
- **Water heating:** At many electric cooperative utilities across the Midwest, participation among eligible customers in water heating load control exceeds 25%.
- **Auto-DR:** At least 12 states had enrolled over 20% of large C&I customers in interruptible tariffs. Automated demand response will be needed to address the challenges of a decarbonizing power grid.

II. Introduction

Introduction

Three major trends are shaping the California energy landscape.

First, it is no surprise that California – an international technology innovation hub – is experiencing a dramatic increase in consumer adoption of clean, flexible energy technologies such as electric vehicles (EVs), batteries, and smart thermostats. California is a leader in a broader global trend toward decarbonized and modernized power systems.

Second, concerns about the stability of the power grid are rising. In particular, California's power supply is struggling to keep up with demand for electricity. This challenge is compounded by supply chain constraints and transmission interconnection delays that prevent large-scale resources from being quickly added to the power grid.

Third, the state's aggressive initiatives to fight climate change are reducing emissions, but also contributing to growing concerns about energy affordability and equity. The energy transition has a price tag, and it will need to progress in a way that remains affordable for all consumers and businesses.

Virtual power plants (VPPs) sit at the center of these trends. VPPs utilize distributed energy technologies such as smart thermostats, batteries, or EV chargers to reduce, shift, or generate electricity when needed. By providing these services to the power system, VPPs could make significant contributions to keeping the lights on while putting money directly in the pockets of consumers who participate.

This study focuses on assessing the potential for realizing the VPP opportunity in California.

Purpose of the study

The purpose of this study is to provide decisionmakers in California with a transparent and actionable understanding of the achievable potential for statewide VPP deployment.

Prior studies – particularly pioneering analysis by Berkeley Lab for the California Public Utilities Commission (CPUC) – have developed highly granular, simulation-based estimates of the potential to provide a variety of valuable load flexibility services to the California power grid.

Our study complements that prior research by developing a current market potential estimate based exclusively on **commercially-available technologies, demonstrated load impacts, and observed customer participation rates across similar program offerings**.

This focus provides decisionmakers with findings that are grounded in real-life experience with existing customer offerings across North America, while tailoring those estimates to the California market and climate.

Grounding Our Market Potential Estimates in Reality

- **Commercially-available technologies:** We limit our analysis to technologies that are already deployed at scale in utility and aggregator programs across the U.S.
- **Observed load impacts:** Customer demand reductions are based on observed impacts in California where available, and otherwise adapted from other jurisdictions and tailored to California weather conditions and customer characteristics.
- **Achievable participation rates:** We support our assumed participation rates with examples of actual enrollment that has been achieved in other jurisdictions.

California's resource adequacy needs

California needs more affordable capacity. VPPs could be a cost-effective solution.

In California, each electricity provider is required to procure enough generation capacity to satisfy its forecasted peak demand, plus a "reserve margin" as insurance against atypical conditions (e.g., an extreme heat wave).

This resource adequacy requirement ensures reliable operation of the power system and incentivizes the development of new resources that can contribute to grid reliability.

Concerns about California's resource adequacy sufficiency are growing due to factors such as increasingly extreme weather events, dependence on intermittent forms of generation, higher demand from electrification, reduced flexibility of hydro systems, and reduced availability of imports from neighboring regions, among others (see sidebar at right).

Additionally, the cost of resource adequacy has doubled since 2017.

As a result, new and creative approaches are necessary to ensure that California has enough capacity available when it is needed most, and that these investments are affordable for customers. VPPs can be a highly valuable resource in this regard.

Recent Resource Adequacy Challenges in California

- In August 2020, a heat wave swept the entire western US. Due to the geographic breadth of the heat wave, California was unable to receive electricity imports from neighboring states. Customers across California experienced blackouts due to insufficient power supply.
- In September 2022, CAISO set a new record for system peak demand of just over 52 GW during a historic heatwave. As utilities prepared to cut off power to hundreds of thousands of customers, the state issued alerts to 27 million homes, asking for voluntary reductions. Blackouts were narrowly avoided.

The current state of VPPs in California

Today, nearly all of California's VPP capacity is in the form of traditional demand response (DR). However, new and innovative VPP offerings are beginning to emerge.

Existing Large-Scale DR Programs

For commercial & industrial (C&I) customers

- Various programs to incentivize load reductions, which vary based on method of compensation and firmness of demand reduction commitment. Programs typically do not include automated response currently.
- Agricultural pumping load control (i.e., irrigation)
- Incentives for customers to adopt automated DR technology and to allow a degree of utility control, subject to limitations
- Time-varying rates, such as time-of-use and critical peak pricing

For residential customers

- Air-conditioning load control, through a smart thermostat or a switch on the home's A/C compressor
- Time-varying rates, such as time-of-use and critical peak pricing
- Rebates for verified voluntary load reductions during DR events

Note: Time-varying rates, rebates for voluntary load reductions, and some C&I interruptible programs do not include automated control of end-uses.

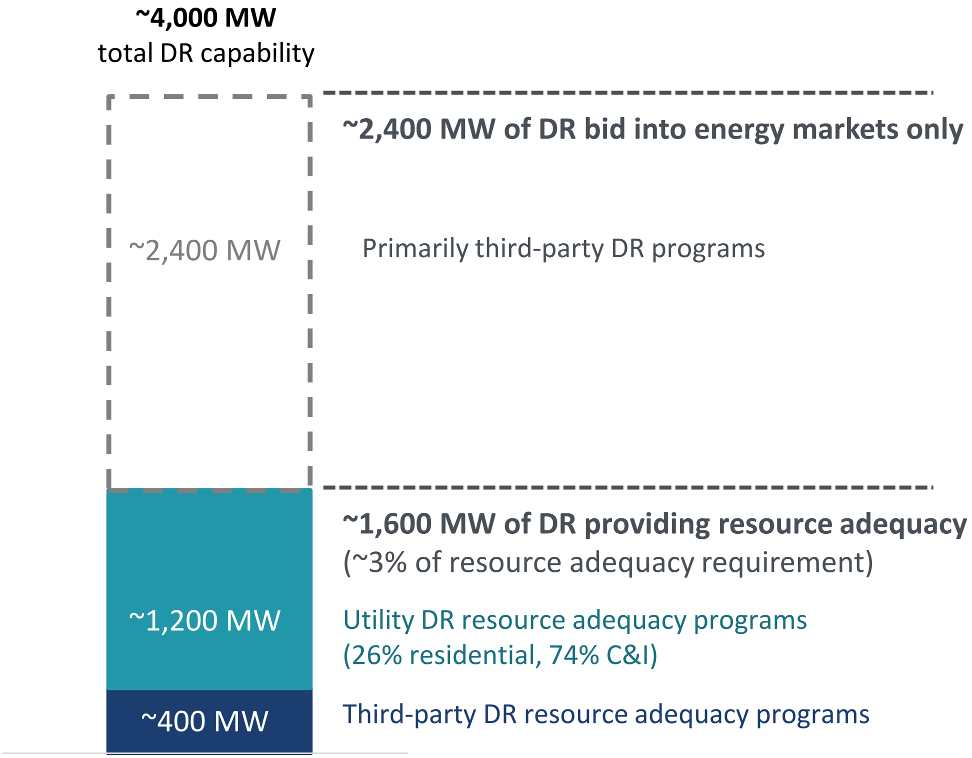
Examples of Emerging VPP Programs

- SunRun and PG&E enrolled 8,500 residential battery owners in a VPP that provided nearly 30 MW of power during summer evenings.
- Companies such as OhmConnect, Tesla, SunPower and others are building battery VPPs to participate in existing California programs such as the Demand Side Grid Support Program and the Emergency Load Relief Program.
- Sacramento Municipal Utility District (SMUD) partnered with Ford, BMW, and GM to introduce a pilot that actively manages the charging of participating EVs to minimize costs to the power system.
- PG&E and Southern California Edison are conducting a pilot involving automated response to dynamic hourly electricity prices from technologies such as batteries, irrigation pumps, EV chargers, and HVAC systems.

California's existing demand response capability

Only a fraction of California's existing DR capacity currently is used to provide resource adequacy. That DR accounts for roughly 3% of the state's total resource adequacy requirement.

2022 Existing Summer DR Capability in California



Source: Brattle analysis of CAISO and EIA data.

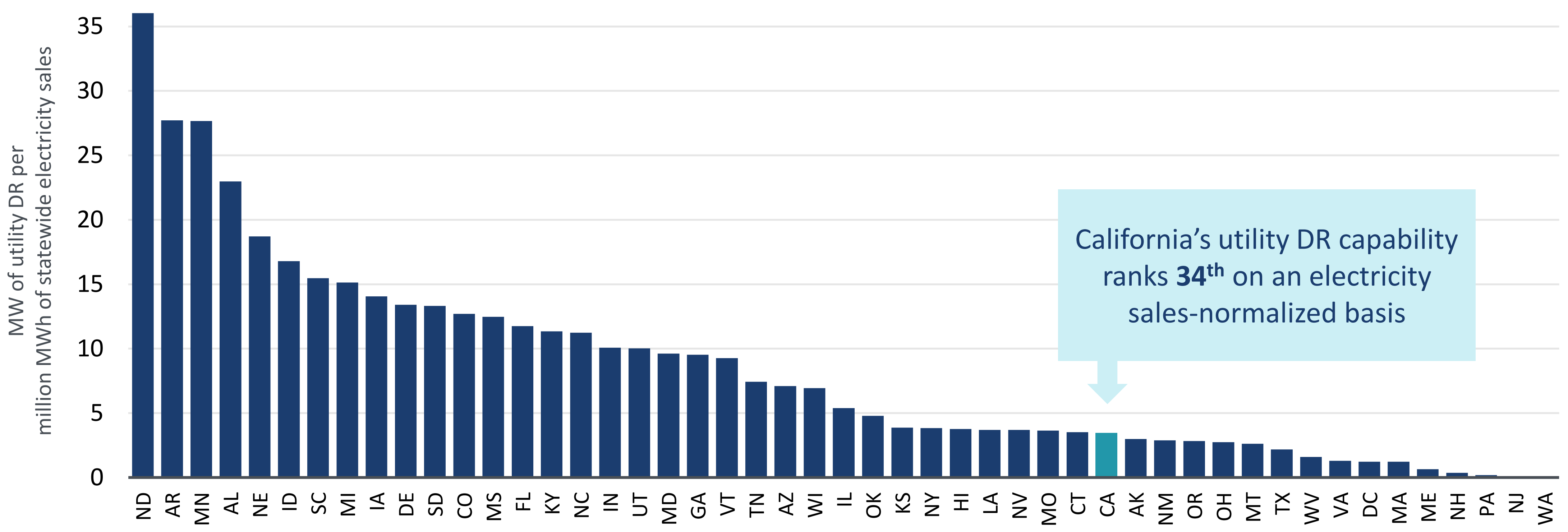
Roles in Delivering DR for Resource Adequacy

- **California Independent System Operator (CAISO):** Trigger DR events, typically during system emergencies and periods of short supply.
- **California Public Utilities Commission (CPUC):** Establish resource adequacy requirements, verify that the requirements are met.
- **Load serving entities (LSEs):** Meet CPUC resource adequacy requirements by developing DR programs or procuring DR capacity from third-party aggregators. Dispatch programs when triggered by CAISO.
- **Third-party aggregators:** Develop and sell DR to LSEs, or administer LSE programs on their behalf. Dispatch programs when triggered by CAISO.
- **Customers:** Participate in LSE and third-party DR programs to provide the demand reductions in return for compensation.

Benchmarking California's demand response capability

Despite being the largest state in the U.S., California's utility-led DR capability is relatively modest. More can be achieved.

2022 Statewide Utility-administered DR Capacity
Normalized by Statewide Electricity Sales



Source: Brattle analysis of 2022 EIA 861 data.

III. Modeling VPP Potential

Scope of the analysis

VPP Technologies

We model five categories of VPP technologies with proven impacts through full-scale commercial deployment:

- Smart thermostats, to control cooling load
- Behind-the-meter batteries
- Electric vehicles
- Grid-interactive electric water heating
- Automated DR for large buildings and facilities

As discussed later in this report, the definition of VPPs could be extended to include other technologies.

Definition of Market Potential

We define "market potential" as all cost-effective VPP capacity that can be developed at achievable, voluntary participation rates.

The participation rates are based on observed enrollment in successful programs in the U.S. and are consistent with the cost-effective participation incentive payments that are supported by our modeling.

Geography

We analyze statewide VPP market potential. The scope includes all California residential, commercial, and industrial customers.

The analysis does not differentiate VPP market potential by utility or zone within the state.

Study Horizon

We focus specifically on VPP potential in the year 2035. That horizon allows sufficient time for emerging technologies to cross the threshold into mass adoption, and for VPP program development to scale.

We do not analyze the annual trajectory of growth in VPP potential between now and 2035.

Key analytical features of the study

The analysis is tailored specifically to California's power system outlook and customer characteristics.

Temporal Granularity

Hourly granularity captures opportunities associated with load shifting and renewables integration. Hourly dispatch simulation is critical for assessing the value that VPPs can provide in addressing the challenges of California's duck curve.

Value Stacking

VPP operations are simulated to maximize total benefits across multiple value streams, while accounting for associated tradeoffs and opportunity costs. We calculate benefits based on California-specific sources such as the CPUC's avoided cost calculator and DR cost-effectiveness protocols.

VPP Dispatch

Simulated dispatch accounts for operational and behavioral constraints inherent in VPP programs, such as availability of load, depth of reduction, and acceptable frequency of curtailment. Impacts are based on California experience where available, such as impact evaluations and load impact protocols filings.

Scenario Analysis

Multi-scenario analysis accounts for uncertainty. Base case market characterization and system outlook aligns with established California studies such as the CEC's Integrated Energy Policy Report and the CPUC's Integrated Resource Plan and Long Term Procurement Plan.

The *FLEX* modeling framework

We use Brattle's *FLEX* model to assesses VPP value by dynamically simulating hourly VPP operations.

1 Parameterize VPP programs

- Build database of new VPP programs
- Estimate per-participant costs and participation
- Identify value proposition and applicable grid services
- Establish load impacts and operational constraints

2 Establish marginal costs and market depth

- Generation capacity value
- T&D value
- Energy value

3 Develop 8,760 hourly avoided costs

Allocate marginal costs based on hourly LOLP | Combine hourly costs to create stacked value profile

4 Optimally dispatch programs and calculate B/C metrics

Simulate optimized hourly dispatch | Calculate total benefits across value streams

5 Identify cost-effective incentive and participation

Establish relationship between adoption and incentives | Identify economic incentive level and associated participation

6 Estimate incremental cost-effective VPP potential

Calculate cost-effective potential by program | Estimate portfolio impacts after participation overlap

Recent Examples of *FLEX* Modeling

FLEX is the analytical engine behind a wide range of high profile studies for utilities, government, research organizations, and technology companies. Examples include:

- U.S. DOE's 2023 VPP Commercial Liftoff Report
- Brattle's 2023 study, Real Reliability: The Value of Virtual Power
- Berkeley Lab's 2023 U.S. Building Sector Decarbonization Scenarios to 2050
- State of Maryland's 2023 GHG Abatement Study
- Xcel Energy Colorado's 2022 Demand Response Potential Study
- U.S. DOE's 2021 A National Roadmap for Grid-Interactive Efficient Buildings
- Pepco's 2021 assessment of electrification impacts in Washington, D.C.

Modeled benefits and costs

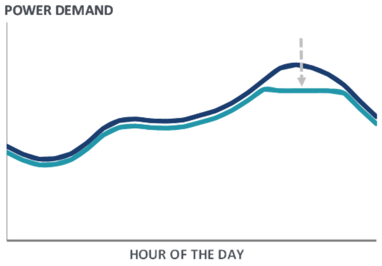
We analyze VPP benefits and costs from the perspective of the utility. This puts VPPs on a level playing field with other resource investment decisions.

Modeled Sources of VPP Operational Value

	Peak Demand Reduction	Load Shifting	Energy reduction
Smart thermostats	✓		✓
Batteries	✓	✓	
Electric vehicles	✓	✓	
Electric water heating	✓	✓	
Auto-DR	✓		✓

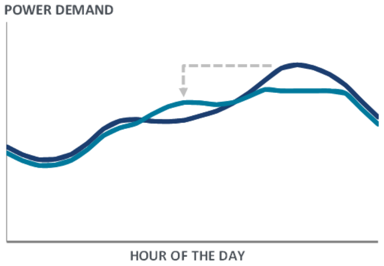
Modeled costs include program administration, marketing and recruitment, equipment, DERMS licensing, and participation incentive payments. See technical appendix for details.

Defining Sources of VPP Operational Value



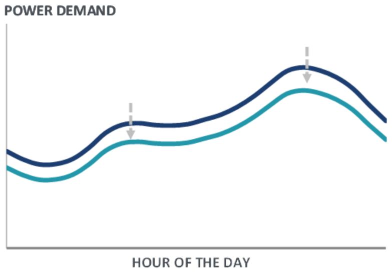
Peak demand reduction

Dispatchable and event-based, with a limited number of events per season. Primarily provides capacity value.



Load shifting

Occurs frequently. Provides capacity and energy value, and potentially GHG emissions reductions. Helps to integrate renewables by reducing curtailments.



Energy reduction

Our analysis includes the complementary energy savings benefit enabled by dispatchable VPP technologies where applicable; standalone energy efficiency measures are outside the scope of this study.

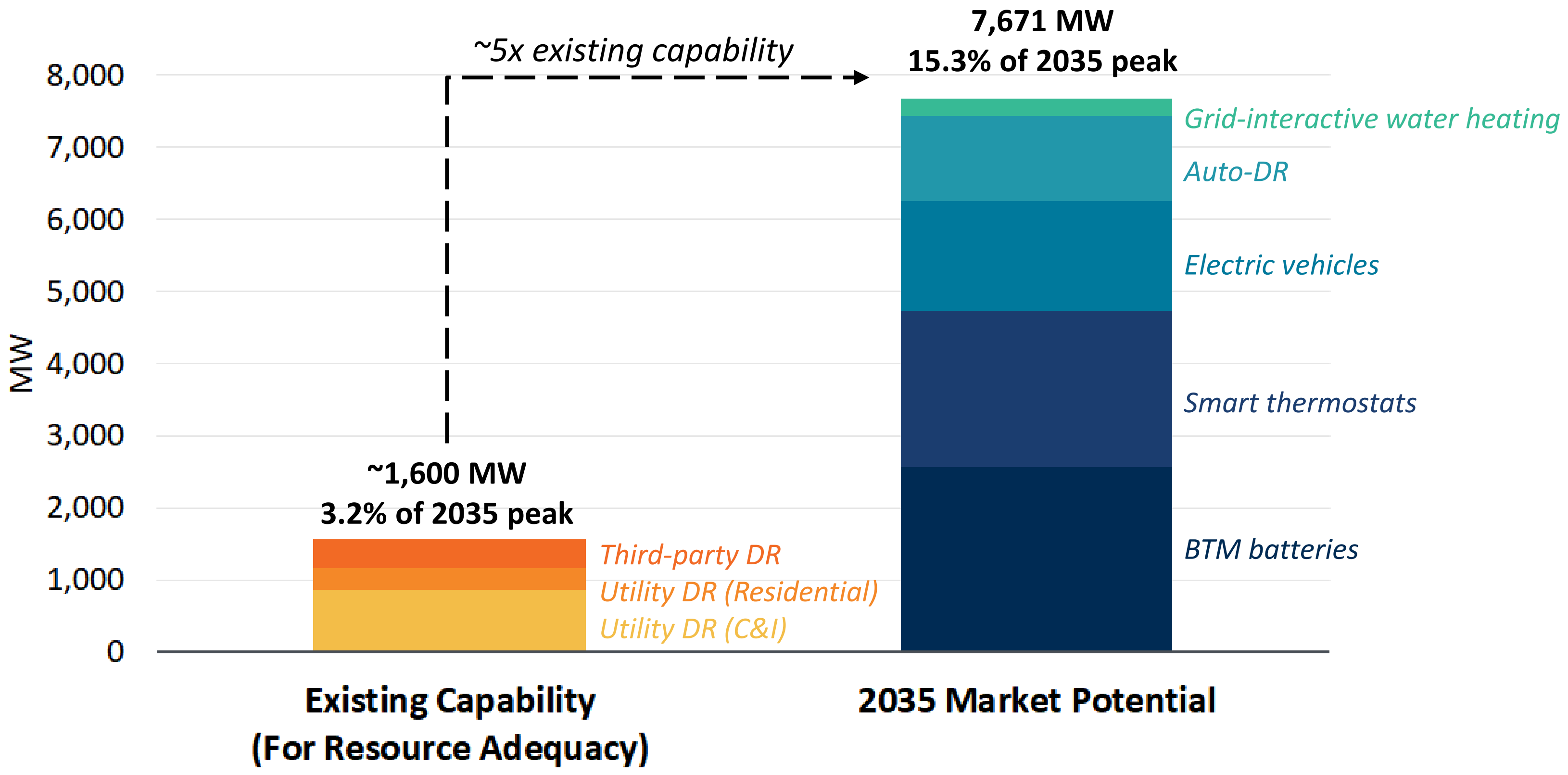
Note: While a potentially considerable additional source of value, we do not model the ability of VPPs to provide ancillary services.

IV. California's 2035 VPP Market Potential

Total statewide VPP potential

California's 2035 VPP market potential is over 7,500 MW, representing over 15% of peak demand. That is roughly five times larger than the DR capacity currently used for resource adequacy.

2035 California Statewide VPP Market Potential

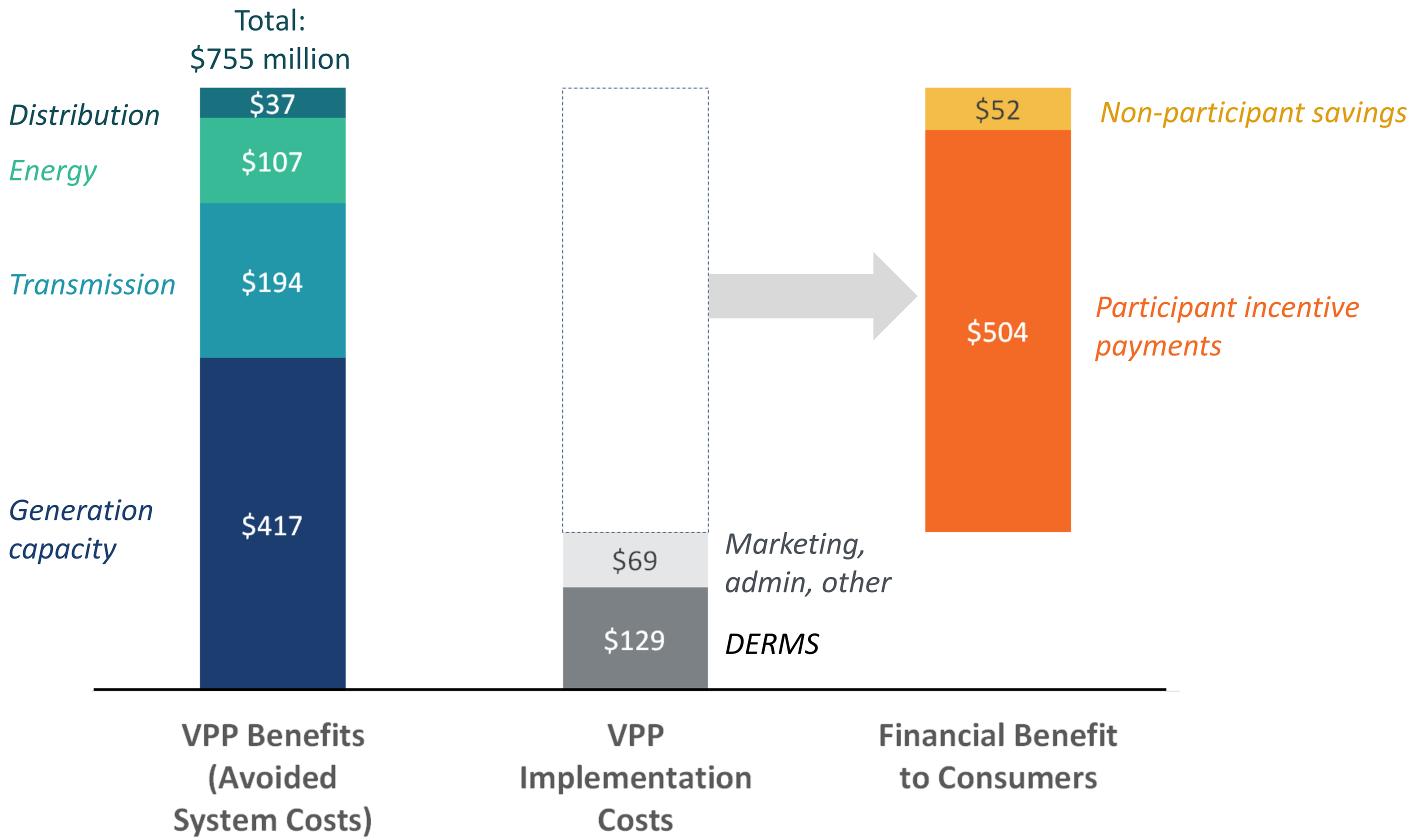


Note: VPP capacity is presented as a percentage of maximum system peak demand during the resource adequacy window of 6 to 11 pm (March-July) and 5 to 10 pm (Other).

The economics of VPP market potential

By 2035, California VPPs could avoid over $750 million/year in traditional power system investment. Roughly $550 million of those savings would be retained by consumers.

2035 Benefits and Costs of Statewide VPP Market Potential ($ Millions)



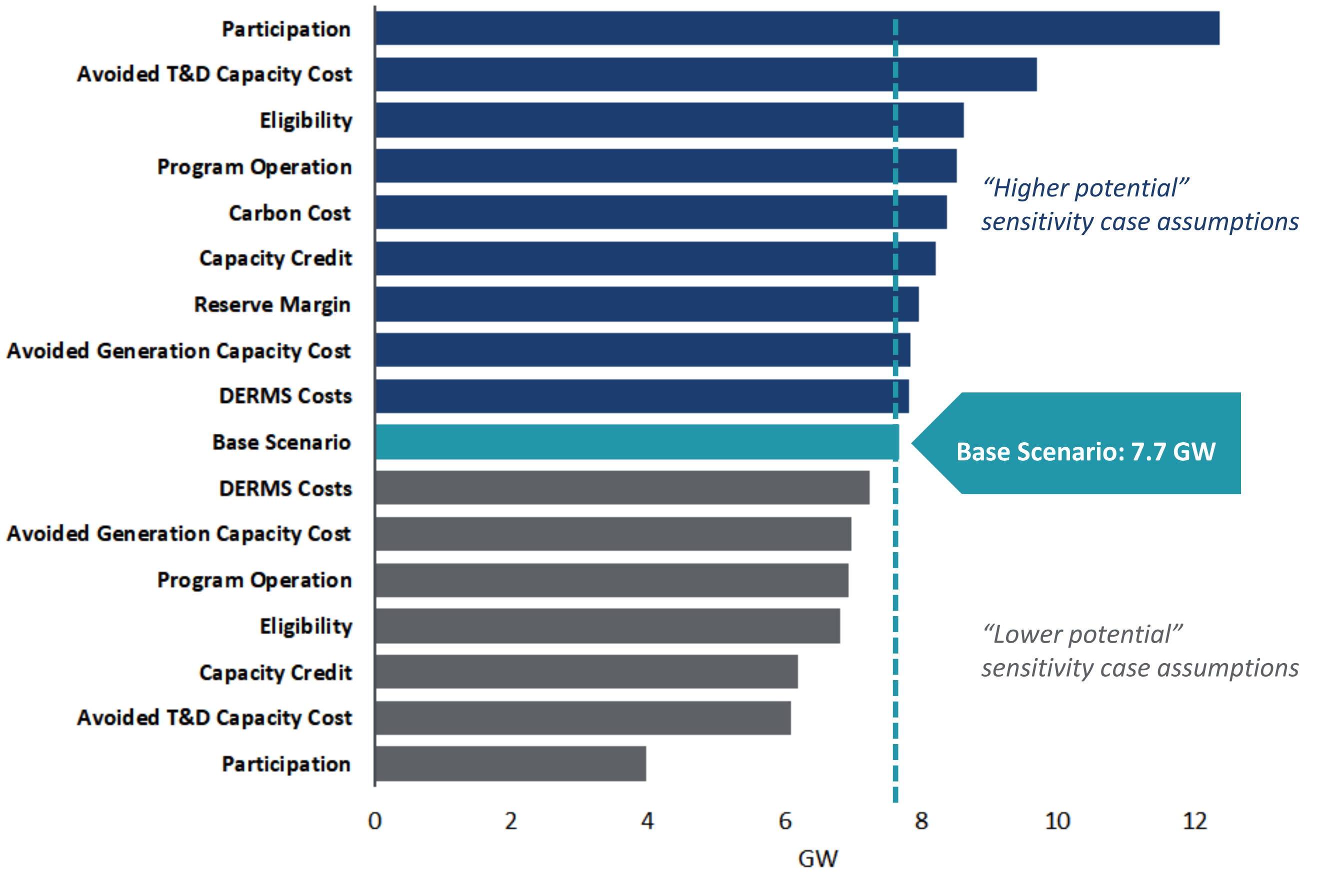
A household participating in all four residential VPP options considered in this study could receive participation payments of **$500 to $1,000 per year**

Note: Values shown in 2023 dollars. Split between participant incentives and non-participant savings will vary depending on program design.

Sensitivity analysis

A lot can change in a decade. We analyzed 17 sensitivity cases to account for uncertainty in the analysis.

2035 Statewide VPP Market Potential: Sensitivity Cases



Key Takeaways

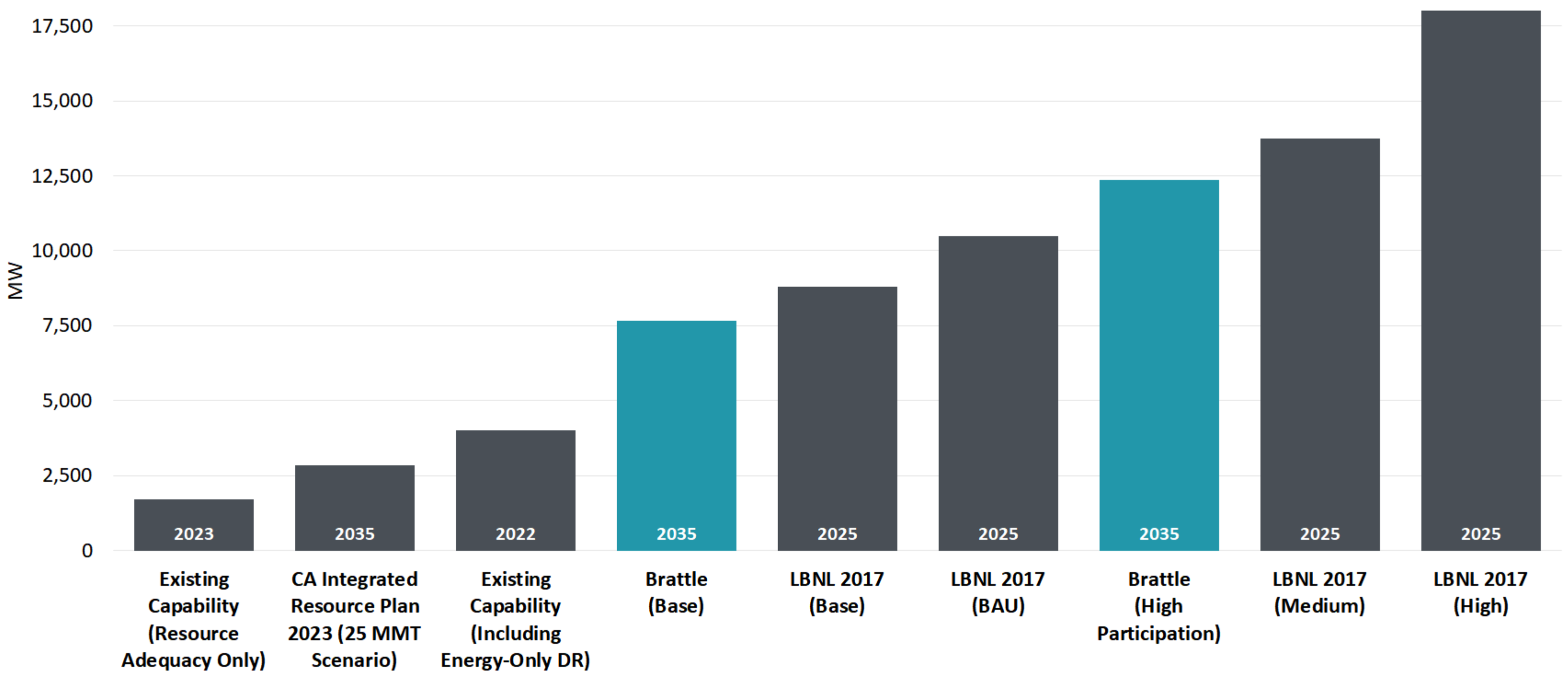
- Participation is a primary driver of the market potential estimate, particularly from customers with batteries. Customer engagement is a critical area for innovation for California's VPP capability to reach levels of participation observed in other jurisdictions.
- The share of customers that adopt flexible technologies such as EVs, batteries, and smart thermostats over the next decade will establish the foundation for VPP program eligibility. The state will need a persistent focus on advancing policies that promote adoption in these areas for our potential estimates to materialize.
- The opportunity for VPPs to defer T&D investments materially influences market potential as well. Regulatory and technical advancements in this area could significantly improve VPP economics. Improvements in VPP dispatch and operational flexibility would provide similar value.

See Volume II: Technical Appendix for more detail on each sensitivity case.

Benchmarking the results

Our assessment of market potential is conservative relative to some other estimates. The difference is explained in part by our focus on commercially available technologies and observed participation rates.

California VPP Capacity Estimates



Sources and Notes: “Existing Capability (Resource Adequacy Only)” from CAISO’s Demand Response Issues and Performance 2023, Table 2.1. “Existing Capability (Including Energy-Only DR)” from CAISO's 2022 Annual Report on Market Issues and Performance, Figure 1.31.. “LBNL 2017” refers to various scenarios from LBNL’s Phase II California Demand Response Potential Study, which provided an estimate of peak demand shedding potential in 2025.

Additional sources of VPP potential

Several additional VPP options are outside the scope of this analysis but would increase the potential.

- **Vehicle-to-grid:** While our study has captured the value associated with curtailing EV charging, there is massive additional technical potential associated with discharging the batteries to provide electricity to the power grid when it is valuable. Recent pilots have begun to demonstrate the technical feasibility of this approach.
- **Behavioral DR:** Our analysis only considers the active control of end-use load. However, time-varying retail rates (e.g., TOU rates), event-based rebates, and new information all are proven to provide meaningful behavioral changes in peak energy consumption. This can be a highly cost-effective form of demand response.
- **EV fleets:** Some types of medium or heavy-duty EV fleets could be attractive candidates for providing demand response. For example, school busses operate on a very predictable schedule and only need to be used during specific times of day. Tapping into the idle battery of those busses while charging could provide valuable services to the power grid.
- **Targeted energy efficiency:** Our analysis is limited to dispatchable forms of demand reduction. However, energy efficiency measures that provide energy savings specifically during valuable times of day also should be considered when making resource investment decisions.
- **Thermal energy storage:** Commercial customers could shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day. For industrial processes, "thermal batteries" could provide demand flexibility and GHG benefits.
- **Pool pumps:** Our analysis did not identify meaningful cost-effective potential for providing resource adequacy from pool pump load control due to their low load and lack of coincidence with late evening net peak hours. However, the CEC's load management standards requiring pool pumps to be pre-scheduled and equipped with communications capability will enable the provision of other services such as daily load shifting.
- **Smart panels:** Advanced circuit panels could act as a gateway to whole-home demand flexibility, providing direct circuit-level metering and control, as well as the potential for device-level load data disaggregation and management over Wi-Fi.

LBNL's California Demand Response Potential Study provides further granular analysis of additional DR options, particularly for the C&I segment.

Additional sources of value

While not quantified in this study, VPPs could help to mitigate two significant challenges in California: Lengthy resource interconnection delays and unprecedented uncertainty in load forecasting.

	Supply-centric approach	VPP-centric approach
Resource development timeline	Transmission-connected resources constrained by 4+ year interconnection approval process	VPPs can be "built" as quickly as customers enroll
Resource development flexibility	Investments in traditional capacity are a 20-40 year commitment once steel is in the ground	VPPs can scale as demand grows and, to an extent, downsize if needed

Other Sources of VPP Value

In addition to the avoided resource costs quantified in our analysis and the two risk mitigation benefits noted on this page, VPPs can provide other benefits as well. Those benefits include:

- Increased renewables deployment
- Better power system integration of electrification
- Enhanced customer satisfaction
- Improved behind-the-meter grid intelligence
- Near-real-time system balancing services and operational benefits

For further discussion, see Real Reliability: The Value of Virtual Power.

For more detail, see Virtual Power Plants: Resource Adequacy without the Interconnection Delays.

V. Technology-level Detail

Introduction

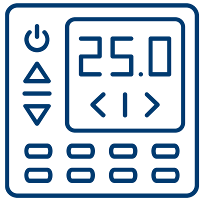
This section summarizes our estimate of 2035 market potential for each VPP technology.

For each of the VPP technologies analyzed, we provide:

- **Examples of successful offerings in other jurisdictions**, which provide practical support for the assumptions in our study
- **Key drivers of VPP potential in California**, such as policy initiatives or expectations around technology adoption
- **Our base case estimate of market potential**, as defined in the prior section of this report
- **Guidance on interpreting the results**, with a particular focus on implementation considerations and factors that could lead to higher or lower potential

We report VPP capacity as the maximum hourly demand reduction that can be provided within the RA window. This effectively represents the nameplate capacity of the VPP.

Smart thermostats



Smart thermostats can be adjusted remotely to reduce air-conditioning load during high priced hours. Pre-cooling strategies, constraints on setpoint adjustments, and a cap on the number of events limits potential loss of customer comfort. Further, self-programming features facilitate overall energy savings.

Examples of Success at Scale

- Air-conditioning load control accounts for most residential VPP capacity that exists in the US today.
- In Minnesota, Xcel Energy has enrolled **more than half** of all eligible residential customers in A/C load control on a voluntary basis (over 400,000 customers).
- Arizona Public Service recently built a 100 MW smart thermostat-based VPP **in just 5 years**, and the program is still growing. APS has successfully called events on multiple consecutive days during a heat wave in which temperatures consistently exceeded 110 degrees.

Key Drivers of California VPP Potential

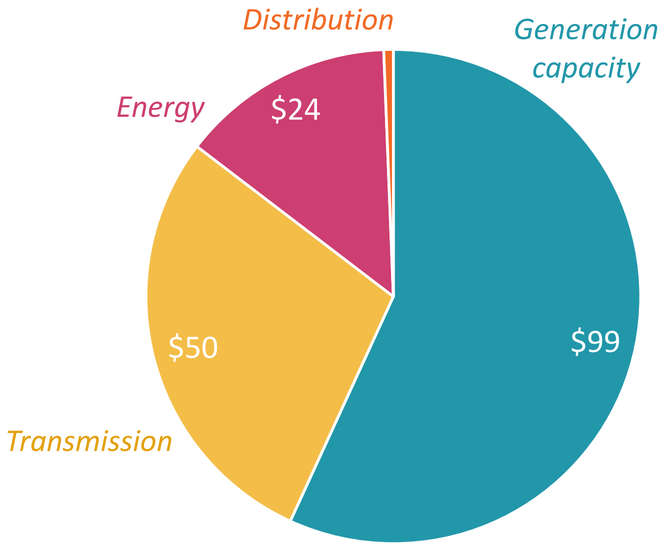
- Continued natural adoption of smart thermostats will organically expand the eligible customer base. We estimate that residential smart thermostat ownership in California could reach 38% of homes by 2035, relative to 14% today.
- California regulations now require smart thermostats in all new commercial buildings, and in residential homes installing a new heat pump.
- California will remain summer peaking for at least the next decade and likely beyond, indicating a continued opportunity to provide resource adequacy through A/C control.

Smart thermostats

2035 Statewide Smart Thermostat VPP Potential

2,162 MW
4.3% of peak

$174 million/yr
in avoided system costs



Interpreting the Results

- "Bring-your-own" (BYO) programs will allow the large number of customers who already own a smart thermostat to unlock additional savings from the device. "New thermostat" programs will attract customers with a free or subsidized smart thermostat, in addition to an ongoing incentive payment.
- When evaluating the benefits of thermostats adopted through a VPP program, it is important to recognize their energy efficiency benefits. Smart thermostats are proven to reduce energy use in addition to providing load flexibility.
- Smart thermostat VPP potential will vary geographically across the state. There is more central air-conditioning and higher air-conditioning load inland than on the coast. Geographically targeted marketing and incentives could increase participation where it provides the most value.

Behind-the-meter batteries

Behind-the-meter (BTM) batteries can be discharged during high-priced hours and charged during low-priced hours, in addition to providing backup generation and bill savings to owners. Program offerings can target existing batteries (e.g., paired with rooftop solar), or incentivize adoption of new batteries.

Examples of Success at Scale

- More than 15 utility BTM battery VPP program offerings exist across the US currently. This number is growing quickly; most of the programs have been introduced in just the past couple of years.
- Green Mountain Power, an early pioneer in this area, already has enrolled **roughly 1% of its residential customer base** in its battery program. GMP recently requested regulatory approval to expand the program as an alternative to conventional distribution system investment, and forecasts that the program will reach between 4% and 8% participation across all residential customers by 2030.
- In Utah, Rocky Mountain Power's WattSmart program has quickly enrolled more than 3,000 participants, including every tenant within a large apartment building. The batteries are dispatched daily.

Key Drivers of California VPP Potential

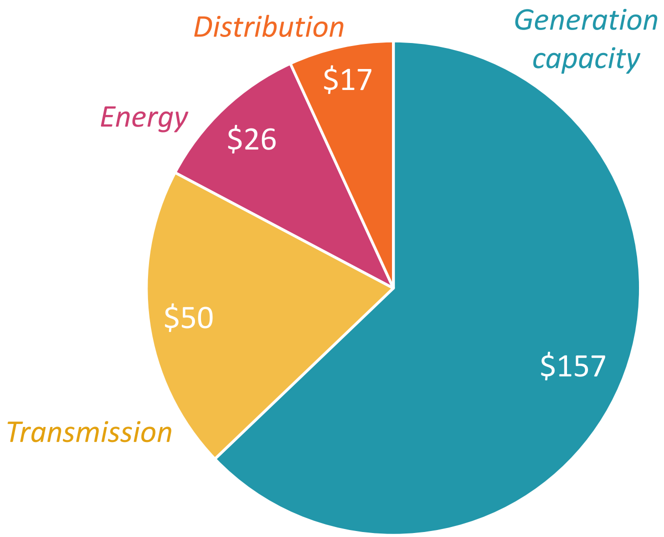
- Resilience concerns, particularly related to wildfires, are driving battery adoption in California. Locally sited resources increasingly are viewed as an efficient alternative to expensive hardening of the T&D system.
- Net energy metering (NEM) reform is driving battery adoption among rooftop solar PV owners. Battery attachment rates to rooftop solar PV in California increased around 80% in 2023 (though solar PV deployment was down by around 70% year-over-year). The CEC forecasts that 6,000 MW of BTM battery capacity will be adopted by 2035, even in the absence of VPP program incentives.
- BTM installations can be a fast way to bring storage capacity online by avoiding interconnection delays; this could accelerate BTM battery deployment in the future if interconnection bottlenecks continue to present challenges.

Behind-the-meter batteries

2035 Statewide BTM Battery VPP Potential

2,569 MW
5.1% of peak

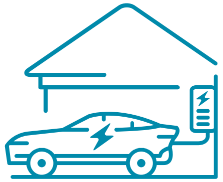
$249 million/yr
in avoided system costs



Interpreting the Results

- BTM batteries represent the single largest source of potential in our analysis, but also are the largest source of uncertainty. The ability of BTM batteries to contribute to California's VPP portfolio will depend on the rate at which the technology is adopted, technical considerations (e.g., panel size), and the extent to which battery owners are willing to enroll in VPP programs.
- In other jurisdictions, avoided T&D costs are a significant driver of participation incentives. This is particularly true in in New England, where utilities can use the programs to avoid high transmission demand charges. Opportunities to compensate for T&D deferral could facilitate battery VPP adoption in California.
- Among the VPP technologies, batteries represent a unique opportunity to provide resilience and improved local reliability. This value to the consumer is incremental to the benefits considered in our analysis. VPP dispatch decisions will need to recognize and preserve this value to participants.
- Whether or not batteries can receive credit for exporting to the grid (beyond reducing the customer's load) will be an important consideration when developing compensation mechanisms. Our analysis assigns system value to exports.

Electric vehicles



Residential EV charging can be managed remotely to shift charging load to low-cost hours when there is otherwise excess supply from renewable generation. Our modeling does not include vehicle-to-grid capability, which could provide additional value once technically and commercially viable.

Examples of Success at Scale

- Time-of-use (TOU) rates for home charging have reached high levels of adoption among EV owners. A survey of early EV TOU offerings found that some utilities had exceeded **40% participation** in voluntary EV TOU rates.
- Actively managed EV charging could provide larger system benefits and therefore larger savings to participants than TOU rates, due to the ability to stagger charging load outside of the event window and more precisely manage load to reduce power system costs.
- Startup company ev.energy already has enrolled **more than 150,000 EVs** in managed charging programs across 40 utilities globally. In California, their managed charging program with Recurve and MCE reduced charging load during peak periods by 95%. A separate program with Silicon Valley Energy shifted 90% of charging load to low-carbon (i.e., mid-day) hours.

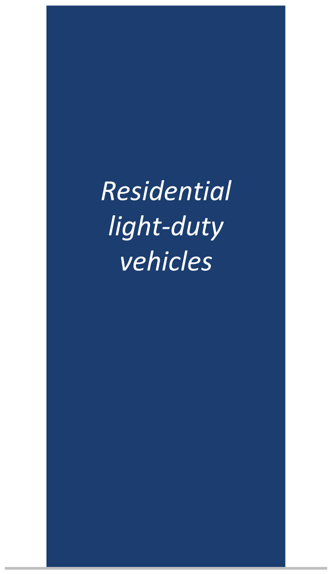
Key Drivers of California VPP Potential

- California has a goal of 5 million electric vehicles on the road by 2030 and 10 million are projected by 2035. According to the IEPR, in 2035 that would contribute 4,500 MW to California's system peak demand if unmitigated.
- 10 million EVs on the road would represent roughly 400 GWh of energy storage capacity by 2035, which exceeds the CPUC IRP's forecast of utility scale battery capacity by a factor of four.
- The coincidence of EV charging with the hours of need for resource adequacy is an important driver of EV VPP potential. In California, the late evening need for RA very closely aligns with home charging demand for customers that are not enrolled in a TOU rate.

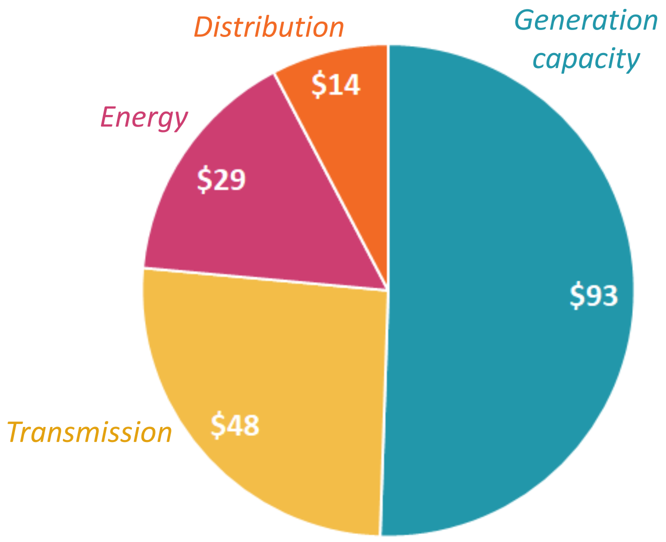
Electric vehicles

2035 Statewide EV VPP Potential

1,528 MW
3.0% of peak



$184 million/yr
in avoided system costs



Note: Analysis includes only light duty vehicle charging, and only load shifting. Medium/heavy duty vehicles and vehicle-to-grid represent additional potential not included in our analysis. Workplace charging was not found to be cost-effective due to lack of coincidence of workplace charging with evening peak demand.

Interpreting the Results

- Our analysis does not consider vehicle-to-grid applications, as these are still being proven commercially. Discharging the EV battery to provide grid services could significantly increase the potential.
- Until EVs reach significant levels of adoption, TOU rates may be the most cost-effective option for shifting load. At higher levels of adoption, actively managing charging will be needed to mitigate strain on the distribution system and provide a broader range of services to the grid.
- Further research is needed to understand the willingness of customers to accept control of their EV charging. On one hand, charging load is flexible, easily automated, and can be managed with no loss of service to the participant. On the other hand, customer concerns around range anxiety and the dependability of new technologies may limit interest, at least initially.

Grid-interactive water heating

Electric water heaters can act as a grid-interactive thermal battery, providing daily load shifting and even real-time grid balancing. Our analysis considers both electric resistance water heaters and heat pump water heaters.

Examples of Success at Scale

- Great River Energy (GRE), an electric cooperative in the Midwest, operates two water heating load control programs that provide daily load shifting and event-based peak demand reductions. 18% of GRE's residential customer base is enrolled in those programs. At several of GRE's member utilities, **participation among eligible customers exceeds 25%.**
- In PJM, companies now are using electric water heaters to provide real-time grid balancing services. For example, Mosaic Power has enrolled roughly 15,000 residential water heaters to provide frequency regulation, and Armada Power has enrolled an additional 12,000 for the same purpose.

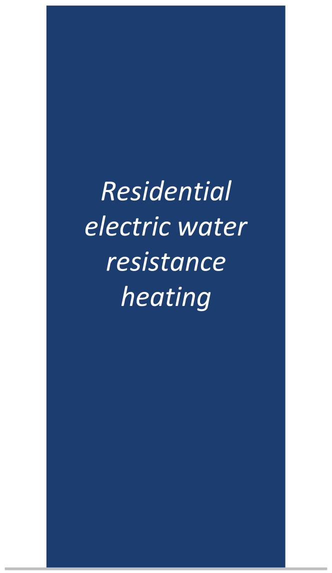
Key Drivers of California VPP Potential

- Water heating in California today largely uses natural gas. Around 10% of households rely on electric water heating.
- CARB's proposed zero-emissions standard for all new water heaters by 2030 is expected to drive significant heat pump adoption. If this target is achieved, we estimate that 45% of residential water heaters will be electric in 2035.
- Incentive programs like the Self-Generation Incentive Program (SGIP) are designed to bring the cost of a HPWH in line with new gas hot water heaters. The program requires new heat pump water heaters to enroll in a DR program and shift electricity consumption to off-peak periods.
- Further, CA Building Standards require that new heat pump water heaters come equipped with a communications port that will dramatically reduce the cost and installation barriers to grid-interactivity.

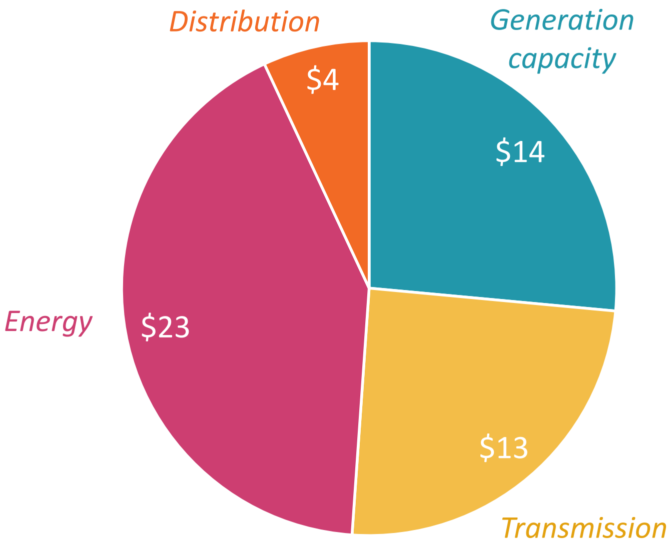
Grid-interactive water heating

2035 Statewide Water Heating VPP Potential

235 MW
0.5% of peak



$54 million/yr
in avoided system costs



Note: The analysis also considered heat pump water heating load control. In the base case the program is marginally cost-effective in the absence of customer incentives, but the net benefits do not support participant incentives that are sufficient to attract meaningful customer participation. All potential shown here is for electric resistance water heaters.

Interpreting the Results

- Our base case analysis only identifies cost-effective potential in controlled electric resistance water heaters. The larger load of those water heaters provides sufficient "bang for the buck" to support the incremental equipment and participation incentive costs of grid-interactivity.
- Our analysis does not consider the potential additional benefit of using electric resistance water heaters to provide ancillary services. Studies have shown that water heaters can provide this value, and robust programs exist in PJM.
- While the incremental cost of controlling heat pump water heaters is low in California due to the state's adoption of the CTA-2045 standard, their efficiency results in relatively low load that is available for control. Absent VPP participation incentives, controlled heat pump water heaters provide positive net benefits, but likely not enough to support sufficient incentives to attract participants according to our base case assumptions. However, the programs do support cost-effective adoption in sensitivity analysis that assumes higher avoided costs.

Auto-DR for C&I customers

Auto-DR connects to the energy management systems of large buildings and facilities to automate and optimize electricity demand reductions in connected end-uses such as lighting and HVAC. The systems also can provide benefits such as improved occupant comfort or overall energy savings.

Examples of Success at Scale

- Historically, large C&I customers have provided the majority of DR capacity in the US. Customer acquisition costs are relatively low, large users often are highly engaged in reducing their energy costs, and some industries have highly flexible electricity demand.
- Analysis for FERC estimated that **at least 12 states had enrolled over 20% of large C&I customers** in interruptible tariffs.
- In California, Voltus has enrolled roughly **900 C&I facilities** in its DR portfolio, representing nearly 100 MW of demand reduction capability. More than half of that portfolio includes a degree of automated control.

Key Drivers of California VPP Potential

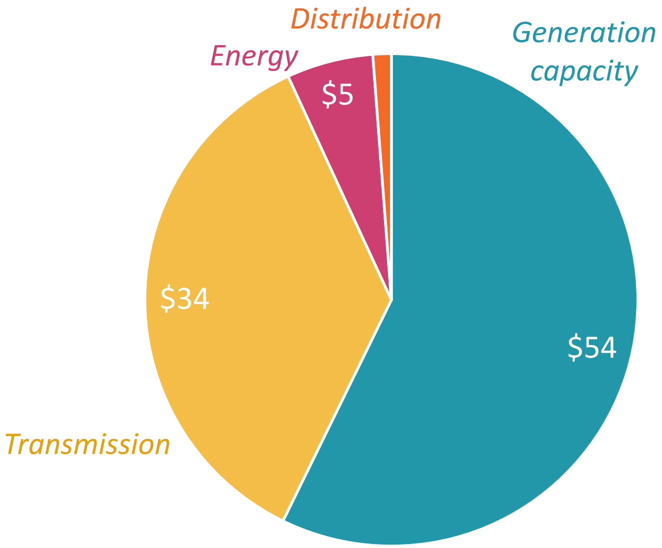
- C&I demand response already is the largest source of load flexibility in California. To address the broader range of operational challenges associated with a decarbonizing power grid in California, VPPs will need to be used more frequently and flexibly in the future than conventional DR has been used in this past. This likely will lead to a shift from manual response to automated control of loads.
- To accelerate deployment of automation in commercial buildings, in March 2024 the CEC initiated a new grant funding opportunity, VPP-FLEX. Further, California utilities offer Auto-DR incentives.
- Additionally, building equipment manufacturers are starting to view load flexibility as an important product offering. For example, Schneider Electric has invested in AutoGrid and Uplight to expand its VPP offerings.

Auto-DR for C&I customers

2035 Statewide Auto-DR VPP Potential

1,178 MW
2.3% of peak

$94 million/yr
in avoided system costs



Interpreting the Results

- "Competition" between conventional (manual) DR and advanced (automated) control through VPPs is an important trend to watch in the C&I DR area over the coming decade.
- The extent to which California's Auto-DR potential materializes will depend on the pace at which the state's power system needs evolve. As shown later in this report, changing power system needs will necessitate more frequent and flexible control of end-uses. While manual response to DR events has been sufficient as an emergency backstop historically, C&I DR likely will need to move in the direction of automation.
- The market potential and economics of Auto-DR will vary significantly by customer segment. While our analysis provides a high-level, C&I class-wide view of the potential, further analysis by customer type would provide valuable insight regarding the customers for which Auto-DR provides the biggest opportunity. Key factors include degree of flexibility in operations and the business's share of operational costs that are related to electricity use. This segmentation analysis could identify additional potential; Berkeley Lab's highly granular California DR Potential Study estimated significantly more potential in the C&I sector than we have identified here.

VI. Other Considerations for Decisionmakers

VPP barriers in California

If not addressed, barriers could prevent California's future VPP potential from being fully realized.

Example barriers facing utilities / load serving entities

- **Participant engagement:** Innovative approaches are needed to make VPP participation attractive to consumers. In addition to financial rewards, consumers need assurance that participation will not detract from their primary intended use of the VPP technologies.
- **Regulatory model:** As a general matter, investor-owned utilities do not have the same financial incentive to deploy demand-side measures as to invest capital in distribution grid upgrades. New business models are needed.
- **Operational experience:** System operators often do not trust VPPs to perform with the same reliability as conventional resources. There should be a focus on developing the ability to fully utilize VPPs and incorporate them into resource planning.

For further discussion:

- Real Reliability: The Value of Virtual Power (The Brattle Group, 2023)
- A National Roadmap for Grid Interactive Efficient Buildings (US DOE, 2022)

Example barriers facing third party providers

- **Market uncertainty:** Opportunities to sell demand reductions, such as the Demand Response Auction Mechanism, often are temporary and do not provide the long-term certainty around which to build a VPP business.
- **Data access:** While improvements have been made to streamline the process of granting AMI data access to third parties, the quality and consistency of the data continues to present challenges.
- **Uncomprehensive valuation:** Evaluations of VPP technologies may consider only a portion of their benefits. For example, a smart thermostat DR program may not also account for the energy efficiency benefits of the technology. Resource planning may oversimplify VPP operational characteristics for modeling purposes.

For further discussion:

- Reinventing Residential Demand Response (OhmConnect, CEC, 2021)
- Setting a New Course: Strategies to Overcoming Barriers to EE and DR Integration into California's DER Markets (CEDMC, 2021)

Achieving the potential

Among many possible paths forward, statewide VPP deployment goals or requirements could drive growth.

If adopted as currently drafted, Senate Bill 1305 would establish a VPP capacity procurement requirement, essentially the equivalent of a renewable portfolio standard for VPPs. In that context, several critical questions will need to be addressed.

Example questions	Considerations
How to determine optimal VPP procurement?	Can IRP models sufficiently represent the nuances of VPP operations? What cost-effectiveness perspective will be used?
How to measure VPP performance?	What methods should be used to quantitatively measure and verify the operational performance of VPPs?
Best practices for enrollment?	What lessons can be learned from other jurisdictions to improve participant engagement in VPP programs?
Technology adoption forecasts?	What will be the basis for forecasting technology adoption? Should it necessarily assume all policy goals are met?
How to prove / improve dependability of VPPs?	What is the optimal balance of program operational performance and program appeal to participants? How to most effectively manage this tradeoff?

Existing VPP Procurement Goals/Requirements

Load shift goal: In 2023, as required by Senate Bill 846, the CEC established a statewide load shift goal of 7,000 MW by 2030. Dispatchable and non-dispatchable demand-side resources count toward achieving the goal. The goal focuses on demand reduction capability during the top 100 system net load hours of the year.

Load management standards: The CEC has the authority to establish standards that promote demand response. Recent load management standards require utilities to develop and standardize the communication of time-varying rates. These requirements are intended to create opportunities for third parties to assist customers in managing their electricity bills through demand response and VPPs.

Peak demand reduction requirements in other jurisdictions

California would not be the only state to establish a peak reduction requirement. Below are four examples.

Maryland. In 2008, state legislation led to the development of EmPOWER MD, which required that a 15% reduction in both per-capita peak demand and energy use be achieved by 2015. Subsequent regulatory action has established ongoing post-2015 reduction targets.

Massachusetts. The state's Clean Peak Energy Standard requires retail electricity providers to meet a portion of peak period load with qualifying clean resources, including reductions in load. The standard focuses on periods of 1 to 4 hours when electricity demand net of renewables output is highest on the power system. The requirement escalates annually and reaches 16.5% by 2030.

Minnesota. In 2017, the Minnesota PUC required that Xcel Energy develop 400 MW of new DR capability (incremental to a large existing DR portfolio) and explore the potential for up to 1,000 MW of new DR additions. Further details are discussed in Xcel Energy's 2019 IRP.

Oregon. The Oregon PUC required PGE to develop at least 77 MW of new winter DR resource and 69 MW of summer DR. The requirement was developed in the context of PGE's 2016 IRP and is discussed in its 2020 Flexible Load Plan.

VPP operations

Greater reliance on VPPs means the resource will need to be used more often than in the past.

VPP dispatch requirements to fully reduce 2035 California system net peak demand

To achieve 1,500 MW net peak demand reduction	*To achieve 7,500 MW net peak demand reduction*
4 total hours of VPP dispatch per year	**114 total hours** of VPP dispatch per year
2 consecutive hours of dispatch on peak day (7 to 9pm)	**6 consecutive hours** of dispatch on peak day (6 pm to 12 am)
2 days of the year requiring dispatch	**36 days of the year** requiring dispatch
1 month of the year requiring dispatch (August)	**5 months of the year** requiring dispatch (June through October)

Notes: The statistics above are for a year with typical weather conditions. Dispatch of the portfolio of VPPs resources could be managed and staggered such that not all resources would need to perform during all times noted above.

VII. Conclusion

Moving forward

By improving the utilization of distributed energy technologies, VPPs reduce the need for new grid resources that otherwise would sit unused for many hours of the year. If this vision is achieved, the result will be a reliable and more affordable power grid for Californians. Our study demonstrates that VPPs could play a significantly larger role in cost-effectively addressing the state's resource adequacy needs in the next decade than they are today.

New policies and other activities could facilitate the achievement of California's VPP potential by driving innovation in areas that currently are limited by a variety of technical, regulatory, economic, and market barriers. We recommend focusing on the following next steps when pursuing the VPP opportunity:

Adopt emerging best practices: VPPs are a rapidly emerging and complex resource being deployed on an international scale. VPP innovation is happening at a relentless pace. Adopting proven models from other jurisdictions is an efficient shortcut to overcoming barriers in California. This will require a deliberate effort to monitor, interpret, and internalize the fast-moving landscape of VPP deployment practices. This type of review can be conducted quickly and updated frequently.

Don't just pilot: Piloting a VPP helps to iron out technological details and consumer engagement strategies before scaling. However, too often successful pilots never leave the pilot stage. If a pilot is necessary, it should be conducted under the assumption that it will succeed and be accompanied with a well-defined, detailed action plan to scale as soon as the pilot's objectives are achieved.

Make VPPs worth it for participants: We need innovation around models for attracting consumers to VPP programs. Can VPP enrollment be coupled with other attractive offers, like subscription pricing? Should new technologies arrive at the consumer's doorstep pre-equipped and even pre-programmed for VPP participation? How do we maximize the value of VPPs to the grid, to justify higher incentive payments to participants?

And make VPPs worth it for implementers. This means aligning utility incentives with the VPP opportunity, such as through performance incentives or allowing utilities to capitalize the operational costs of VPPs. For third party aggregators, it could mean better access to wholesale markets, more opportunities to participate in distribution investment deferral opportunities (i.e., "non-wires solutions"), or the wide-scale introduction of more granular time-varying rate structures.

Further reading

Alstone, Peter et. al., "2015 California Demand Response Potential Study," Lawrence Berkeley National Laboratory report, April 2016.

Alstone, Peter et. al., "2025 California Demand Response Potential Study," Lawrence Berkeley National Laboratory report, March 2017.

Brehm, Kevin, Avery McEvoy, Connor Usry, and Mark Dyson, "Virtual Power Plants, Real Benefits," RMI report, January 2023.

Downing, Jennifer et. al., "Pathways to Commercial Liftoff: Virtual Power Plants," U.S. Department of Energy report, September 2023.

Garth, Lakin and Trevor Gibson, "Plugging In: How Customer Engagement Powers the Potential of VPPs," SEPA brief, February 2024.

Gerke, Brian et. al., "The California Demand Response Potential Study, Phase 3," Lawrence Berkeley National Laboratory report, July 2020.

Hledik, Ryan, and Kate Peters, "Real Reliability: The Value of Virtual Power," prepared for Google, May 2023.

Hledik, Ryan, Kala Viswanathan, and Kate Peters, "Incentivizing Behind-the-Meter Storage: A Jurisdictional Review", prepared for SunRun, December 2023.

Hledik, Ryan, Kala Viswanathan, and Kate Peters, "Virtual Power Plants: Resource Adequacy without Interconnection Delays," Utility Dive op-ed, August 2023.

Hledik, Ryan, Ahmad Faruqui and Tony Lee, "The National Potential for Load Flexibility," Brattle report, June 2019.

Hledik, Ryan, Sanem Sergici, Michael Hagerty, and Julia Olszewski, "An Assessment of Electrification Impacts on the Pepco DC System," Brattle report prepared for Pepco, August 2021.

Further reading

Langevin, Jared Aven Satre-Meloy, Andrew Satchwell, Ryan Hledik, Julia Olszewski, Kate Peters, and Handi Chandra Putra, "The Role of Buildings in U.S. Energy System Decarbonization by Mid-Century," pre-print, October 2022.

McEvoy, Avery, Alex Walmsley, Kevin Brehm, Lauren Shwisberg, "VPP Policy Principles," VP3 report, February 2024.

Satchwell, Andrew and Ryan Hledik, "Making Grid-interactive Efficient Buildings a "Win" for Both Customers and Utilities," prepared for 2022 ACEEE Summer Study on Energy Efficiency in Buildings, August 2022.

Sergici, Sanem, Ryan Hledik, Michael Hagerty, Ahmad Faruqui, and Kate Peters, "The Customer Action Pathway to National Decarbonization," Brattle report for Oracle, September 2021.

U.S. Department of Energy, "A National Roadmap for Grid-Interactive Efficient Buildings," prepared by Berkeley Lab, The Brattle Group, Energy Solutions, and Wedgemere Group, May 2021.

Clarity in the face of complexity

Brattle