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

VOLUME II: TECHNICAL APPENDIX
APRIL 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, other consultants, or the reviewers listed below.

We would like to thank Ric O'Connell for the invaluable project management and insights he provided throughout the development of this report. We also are grateful to for review of a draft of this study by the following organizations: Ava Community Energy (Feliz Ventura), Google (Rizwan Naveed), OhmConnect (Cliff Staton), Recurve (Brian Gerke), Swell (Sarah Delisle, Jon Fortune).

CONTENTS

I. Introduction

This study assessed the statewide market potential for virtual power plants (VPPs) in California in 2035. We describe the findings of the study in our Volume I summary report. This Volume II report details the modeling approach and assumptions underlying the analysis.

II. The California Power System

System Net Load

To develop the California system net load profile, we relied on the 2035 hourly load forecast from the CEC's 2023 Integrated Energy Policy Report (IEPR).[1] We subtracted hourly renewable generation from the hourly system load to determine California's hourly "net load." Hourly renewable generation forecasts for 2035 were from California Public Utilities Commission (CPUC) integrated resource plan (IRP) capacity forecasts for the "25 MMT portfolio" and CPUC renewable profiles for the 2020 weather year.[2]

The system load shape is expected to change between now and 2035 due to electrification and increased renewable penetration. To account for this change, we define resource adequacy (RA) windows based on the forecasted peak net load hours for each month, similar to the method currently used in California.[3] We identified 5 p.m. through 10 p.m. as the highest five hours of net load from August to February, and 6 p.m. to 11 p.m. as the highest net load hours from March to July. These RA windows tend to be the highest risk hours for supply shortfalls and therefore identify the operational need for additional capacity.

Marginal Hourly Energy Costs and Ancillary Services

To establish marginal energy costs, we use the 2035 hourly energy prices from the 2023 California Avoided Cost Calculator (ACC) model.[4] Because we are quantifying statewide VPP potential, we use a load-weighted average of NP-15 and SP-15 zonal hourly energy prices to represent the marginal energy costs. When estimating avoided energy costs, we gross up load

---

1 2023 IEPR Hourly Forecast. "Baseline Net Load" for CAISO Planning Scenario.

2 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/system-reliability-modeling-datasets-2023

3 Final-2024-Flexible-Capacity-Needs-Assessment-v2.pdf (caiso.com)

4 https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

impacts by 9.5% to account for avoided energy losses that otherwise would be associated with transporting electricity from generators to customers over the T&D system.[5]

We account for only a portion of ancillary services benefits that may be provided by the VPP programs. Specifically, we do not model VPPs as explicitly being dispatched to provide ancillary services in the market.[6] Instead, we account for the potential for VPPs to reduce load in high-demand hours and, as a result, reduce ancillary services procurement obligations in those hours. We add an ancillary services cost to the modeled energy prices, based on the 2035 hourly avoided ancillary services procurement costs from the ACC for NP-15.[7]

The avoided marginal energy prices are zonal averages and do not capture local nodal congestion. VPPs could provide additional system benefits not quantified in this study if they are located in congested portions of the grid. We choose to highlight VPP value under "normal" conditions, with the understanding that VPPs would provide additional value in systems with high congestion. The avoided transmission and distribution benefit captures some congestion relief value.

Additionally, while the hourly marginal energy costs in the ACC model appear to be consistent with recent day-ahead energy price volatility, the ACC energy costs do not fully represent real-time energy market price volatility. VPPs potentially could provide significant additional energy benefits not quantified in this study by reducing exposure to large price spikes in the real-time market.

Avoided Generation Capacity Costs

VPP dispatch during high system resource adequacy risk hours can defer the need for additional supply-side capacity resources. For the base case, we value avoided generation capacity costs at recent 2023 California RA contract prices, $6.35/kW-mo or $76.20/kW-yr (in 2023 dollars). Although VPPs are located behind the customer meter, we do not gross up the avoided generation capacity by a reserve margin in the base case due to recent recommendations from CAISO adopted by the CPUC.[8]

---

5 Losses are load-weighted generation losses for the three utilities from the ACC, https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

6 For example, some VPP programs may be able to provide spinning reserves or frequency regulation, which requires providing fast automated response to signals from the system operator.

7 https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

8 https://www.caiso.com/Documents/Demand-Response-Report-2023-Mar-6-2024.pdf

We attribute an effective load carrying capability (ELCC) value to each specific VPP program, informed by the 2021 CAISO ELCC Study that forecasted a range of demand response capacity values.[9] For the base case, we assume event-limited programs (like auto-DR or smart thermostat programs) contribute 60% capacity value (relative to the aggregate capacity of the portfolio) while VPP programs with more frequent dispatch capability (like grid-interactive water heating) contribute 80% capacity value.

California RA contract prices and the value of capacity have fluctuated greatly in recent years, and there is uncertainty around the price of capacity in 2035. We account for this uncertainty by running sensitivity cases with a range of avoided generation cost assumptions. We also test the sensitivity to resource ELCC value and the assumed reserve margin. For more details on these sensitivity cases, see the "Sensitivity Cases" section of this report.

Avoided Transmission and Distribution (T&D) Capacity Costs

Resources located behind the customer's meter can avoid transmission and distribution system upgrades by providing resource adequacy at the load source. Avoided transmission and distribution system costs vary across utilities and even significantly within a utility service territory (due to considerations such as available headroom in a given location, variations in population density across the system, or undergrounding of power lines). We use representative utility avoided T&D values and hourly allocations to represent potential California-wide T&D deferral value from demand-side resources. We test additional assumptions in the sensitivity cases.

For the base case, we assume avoided transmission costs of $59.10/kW-yr based on the PG&E costs in the 2023 California ACC model.[10] We allocate the deferred transmission value proportionally to the top 112 hours of forecasted CAISO system 2035 load from the IEPR. We assume 112 hours because this is the weighted average of the three utility allocations in the ACC model.

For consistency in our analysis of T&D benefits, the base case avoided distribution cost also comes from the PG&E ACC model assumption and is $24.75/kW-yr.[11] We allocate the distribution value using the hourly allocation from the ACC for PG&E Climate Zone 5. Deferred

---

9 "Effective Load Carrying Capability (ELCC) Study Results for Demand Response (DR) Resources" https://www.caiso.com/Documents/Presentation-ELCCStudyResults-DemandResponseResources-Jun24-2021.pdf

10 https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

11 Ibid.

distribution investment is variable across a region due to geographically localized differences in customer loads and available headroom across the service territory.

Our estimates of avoided T&D costs account for avoided line losses. When modeling PG&E avoided T&D costs in the base case, we assume 8.3% losses for energy flows across transmission lines and 4.8% losses for flows across distribution lines.[12]

Avoided Emissions Costs

Our base case focuses on avoided resource costs, so it does not include any avoided emissions value. However, we model a sensitivity case that attributes avoided emissions value to VPPs using a method that is consistent with the Avoided Cost Calculator. More details are summarized in the “Sensitivity Cases” section of this report.

Customer Base

We establish statewide customer counts using 2022 EIA Form 861 California estimates for residential and commercial & industrial (C&I) customers.[13] We forecast residential and C&I customer growth through 2035 using a 0.5% annual growth rate consistent with the IEPR, and 0.6% commercial growth informed by the EIA AEO 2023.[14] We split the C&I class into customer segments defined by customer peak demand as informed by previous analysis for a national FERC Demand Response study.[15] Small C&I customers have peak demands < 20 kW, medium C&I between 20 kW and 200 kW, and large C&I > 200 kW. Customer counts are shown in Table 1 for 2035 by class.

TABLE 1: CALIFORNIA CUSTOMER COUNTS BY CLASS (2035)

Customer Class	Customers
Residential	19,981,202
Small C&I	2,328,772
Medium C&I	448,153
Large C&I	26,402

[12] Ibid.

[13] United States Energy Information Administration (EIA) Annual Electric Power Industry Report, Form EIA-861, 2022.

[14] https://www.eia.gov/outlooks/aeo/

[15] 2009 FERC Study (Table D-1, pdf 209)

III. The Virtual Power Plant

We model the operations and net costs associated with a range of residential and C&I demand response programs. Our modeled VPP only includes programs with direct utility or aggregator control over customer end uses. We exclude time-varying rates, behavioral demand response programs, energy efficiency, and other non-dispatchable resources from our analysis, although those resources could contribute meaningfully to meeting system load in the future. The Volume I report includes further discussion in this regard.

Eligibility

Customer eligibility for each modeled VPP program is limited to the share of customers expected to own the applicable technology (e.g., an electric vehicle or smart thermostat) by 2035. We base technology penetration assumptions on California-specific sources where available and test these assumptions through sensitivity analysis. Of the eligible customers, only a portion will participate in the modeled programs.

Note that the smart thermostat and storage programs each have two offerings. The bring-your-own (BYO) offering targets customers that already have adopted the technology, and provides incentives to enroll the technology in the VPP program. The “new thermostat” and “new battery” offerings financially incentivize the adoption of those technologies in return for participation in the VPP program. Table 2 summarizes the eligibility assumptions.

TABLE 2: ASSUMED 2035 ELIGIBILITY RATES (% OF CUSTOMER SEGMENT)

Program	Customer Segment	Eligibility	Source Description
Smart Thermostat (new tstat)	Residential	35.8%	All customers with central A/C[16] plus non-CAC customers who adopt heat pumps,[17] who will not naturally adopt a smart thermostat[18]
Smart Thermostat (BYO)	Residential	28.3%	Naturally occurring smart thermostat adoption (i.e., in the absence of a new VPP program)[19] and additional customers who adopt heat pumps[20]
Grid-Interactive Water Heating	Residential	6.0%	Customers with electric resistance water heaters[21]
Heat Pump Water Heating	Residential	37.0%	Customers with heat pump water heaters, all with CTA-2045[22]
EV Managed Charging – At Home	Residential	49.0%	9.8 million electric LDVs in 2035 from CEC baseline forecast[23]
Storage (new battery)	Residential	97.7%	Customers that will not naturally adopt a battery (i.e., in the absence of VPP participation incentives)

16 https://www.energy.ca.gov/publications/2021/2019-california-residential-appliance-saturation-study-rass

17 Assume goal of 6 million heat pumps by 2030 is met, with 50% installations in residential homes, 25% which are in homes that do not already have central cooling. https://www.gov.ca.gov/2022/07/22/governor-newsom-calls-for-bold-actions-to-move-faster-toward-climate-goals/

18 Subtract the BYO program eligibility forecast from the central A/C + new central cooling customers who adopt heat pumps.

19 Assume current share (14%) of customers with a smart thermostat will increase to 17% based on natural smart thermostat adoption at a CAGR of 1.7%. https://www.energy.ca.gov/publications/2021/2019-california-residential-appliance-saturation-study-rass and https://guidehouseinsights.com/reports/market-data-smart-thermostats

20 New heat pump customers will have a smart thermostat based on CA Title 24 mandates. Assume that the current share (30%) of these new heat pump customers already had a smart thermostat controlling their central cooling load. https://www.title24express.com/what-is-title-24/title-24-hvac/

21 https://www.energy.ca.gov/publications/2021/2019-california-residential-appliance-saturation-study-rass

22 There are very few water heat pumps in California today. Assume 2035 penetration based on annual sales and a ramp up (starting at 20% in 2026) to a 2030 target that all new water heating equipment sales are heat pumps. https://www.energy.ca.gov/sites/default/files/2022-11/DAWG_Additional_Achievable_Energy_Efficiency_and_Fuel_Substitution_2022-11-15_ADA.pdf and https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-provides-additional-incentives-and-framework-for-electric-heat-pump-water-heater-program

23 https://www.energy.ca.gov/media/7494

Storage (BYO)	Residential	2.3%	Customers with BTM batteries in 2035, as forecasted by the CEC[24]
Pool Pump	Residential	9.0%	Customers with a pool[25]
Storage (new battery)	All C&I	99.1%	Customers that will not naturally adopt a battery (i.e., in the absence of VPP participation incentives)
Storage (BYO)	All C&I	0.9%	Customers with BTM batteries in 2035, as forecasted by the CEC[26]
Smart Thermostat (new tstat)	Small C&I	56.6%	Customers with central cooling and heat pumps, who will not have a smart thermostat based on BYO forecast[27]
Smart Thermostat (BYO)	Small C&I	18.4%	Naturally occurring smart thermostat adoption, plus additional heat pump adoption[28]
Auto-DR	Medium C&I	100.0%	All customers are eligible
Auto-DR	Large C&I	100.0%	All customers are eligible
EV Managed Charging – At Work	Residential	49.0%	9.8M electric LDVs in 2035 from CEC baseline forecast[29]

Participation

We base participation assumptions for each program on a review of enrollment rates that have been achieved in successful DR and VPP program offerings across the US. The Volume I report provides examples of participation rates for each VPP program that match or exceed those used in our study.

Further, our participation assumptions are consistent with a meta-analysis of regional market potential studies across the US. These studies use methods such as primary market research

24 CEC forecasts 3,500 MW of residential storage by 2035 based on billing tariff, solar attachment rates, Title 24, and other non-VPP adoption incentives. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253096&DocumentContentId=88302

25 https://www.energy.ca.gov/publications/2021/2019-california-residential-appliance-saturation-study-rass

26 CEC forecasts 2,500 MW of commercial storage by 2035 based on billing tariff, solar attachment rates, Title 24, and other non-VPP adoption incentives. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253096&DocumentContentId=88302

27 EIA CBECS for Pacific region for customers with packaged air conditioning units and existing heat pumps. Additional heat pump adoption growth assumed to occur at the same rate as the residential class, based on the mandate. This value excludes customers who will naturally adopt smart thermostats forecasted in the BYO program.

28 EIA CBECS for Pacific region for current commercial smart thermostat saturation. Additional heat pump smart thermostat adoption driven by Title 24 and assumed to occur at the same rate as the residential class.

29 https://www.energy.ca.gov/media/7494

(customer surveys), reviews of achieved participation in successful DR programs, interviews with customer account managers, reviews of utility DR plans, and expert judgment to establish achievable participation rates for the modeled programs.[30]

In our modeling, the participation assumptions are dynamic and a function of the maximum cost-effective participation incentive that could be offered based on other program implementation costs and the modeled benefits (i.e., avoided generation capacity cost, energy cost, and T&D cost). Without this functionality, the analysis would under-represent the potential for a given VPP program, or could even exclude it from the analysis entirely based on inaccurate assumptions about uneconomic incentive payment levels.

We first estimate the net benefits of the program in the absence of incentive payments to determine the maximum cost-effective incentive payment that can be offered to participants. The assumed participation estimate is adjusted up or down to be consistent with the maximum incentive payment. The participation-incentive function for each program is derived from the results of a 2013 market research study[31], which tested customer willingness to participate in VPP programs at various incentive levels, and a review of a subsequent study analyzing U.S DR program and incentive data.[32]

An illustration of the participation function for a residential program is provided in Figure 1. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis). At an incentive level of around $20/yr, around 20% of eligible customers would participate in the program. If the economics of the program could only justify an incentive payment of less than this (e.g., due to low avoided capacity costs), participation would decrease according to the blue line in the chart, and vice versa. Below an incentive payment level of around $10/yr, customer willingness to enroll in the program quickly drops off. Above an incentive payment of around $50/year, participation levels off at around 35%, the maximum observed participation in this illustration. Our modeled participation rates are shown in Table 3 after cost-effective incentive adjustments.

[30] See a summary of existing utility program participation rates at https://gebroadmap.lbl.gov/

[31] Ahmad Faruqui, Ryan Hledik, David Lineweber, and Allison Shellaway, "Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential," June 2013.

[32] https://www.bpa.gov/-/media/Aep/energy-efficiency/technology-demand-response-resources/180319-bpa-dr-potential-assessment.pdf

FIGURE 1: ILLUSTRATION OF RESIDENTIAL ENROLLMENT AS A FUNCTION OF INCENTIVE

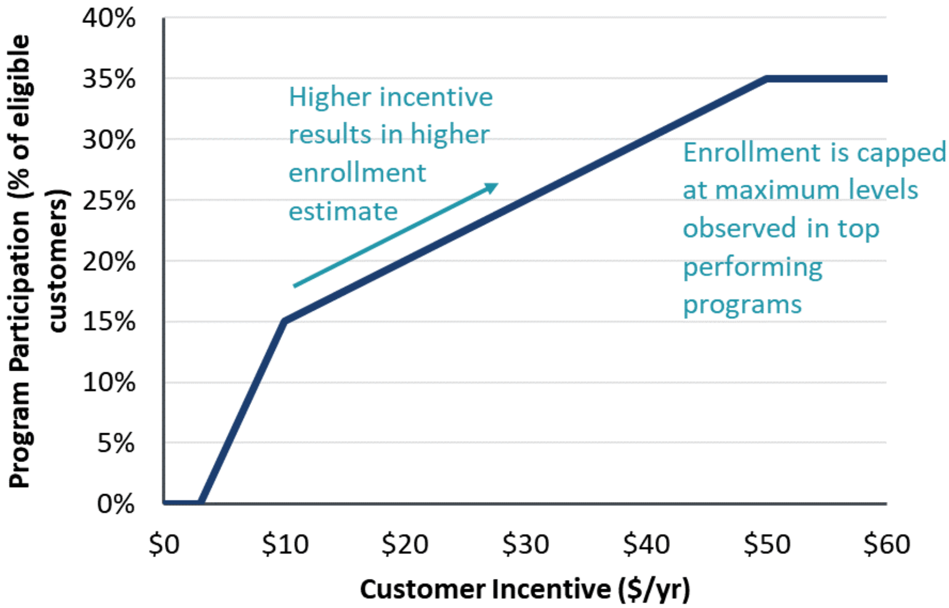

TABLE 3: ASSUMED PARTICIPATION RATES

Program	Customer Segment	Participation (% of eligible customers)
Smart Thermostat (new tstat)	Residential	26%
Smart Thermostat (BYO)	Residential	29%
Grid-Interactive Water Heating	Residential	41%
Heat Pump Water Heating	Residential	0%[33]
EV Managed Charging – At Home	Residential	26%
Storage (new battery)	Residential	See below
Storage (BYO)	Residential	See below
Pool Pump	Residential	0%
Storage (new battery)	All C&I	See below
Storage (BYO)	All C&I	See below
Smart Thermostat (new tstat)	Small C&I	21%
Smart Thermostat (BYO)	Small C&I	23%
Auto-DR	Medium C&I	21%
Auto-DR	Large C&I	21%
EV Managed Charging – At Work	Residential	0%

We develop residential battery participation assumptions based on the initial experience of Green Mountain Power's behind-the-meter storage program. We assume 1% of all residential customers in California will adopt a behind-the-meter storage battery asset and enroll in a VPP program by 2035, based on our estimate of existing participation in Green Mountain Power's program.[34] This represents the total participation of both the BYO and new battery programs combined. Among those participants, for the BYO program, we assume that 20% of customers who are forecasted in the IEPR to naturally adopt a storage asset (i.e., absent a VPP program) would choose to enroll in our modeled program.

For C&I customers, we also assume that 20% of customers forecasted to own a battery in the IEPR will participate in a VPP program. We then apply the ratio of "new battery" to BYO participants from the residential class to establish the number of "new battery" participants

33 Programs with 0% participation are not cost-effective in our base case.

34 https://greenmountainpower.com/wp-content/uploads/2021/12/2021-Integrated-Resource-Plan.pdf

among C&I customers. The result is an assumption that 0.2% of all C&I customers will have a battery asset and enroll in a VPP by 2035.

Program Operations

We use Brattle's *FLEX* model (described below) to simulate optimized VPP dispatch relative to hourly system costs, subject to detailed accounting for the operational constraints of each VPP program. Our analysis accounts for program limitations designed to maintain a sufficient level of customer service (e.g., how often the program can be called, hours of the day when it can be called). We also limit the hourly load interruption capability for each program based on an average load profile of a portfolio of each end-use technology. For instance, for home EV managed charging, our modeling accounts for average home charging patterns across a fleet of EVs, which provides greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

Per-participant load impacts are based on a review of existing California program impact evaluation studies and technology performance characteristics. Program load impacts vary by hour – based on when the event is called and how much customer load is available to curtail. Sources of impact assumptions are described in Table 4. We test additional sensitivities around event duration and frequency.

TABLE 4: VPP OPERATIONAL CHARACTERISTICS

Program	Per Participant Peak Impact[35]	Event Frequency	Load Building Assumptions
Smart Thermostat (BYO and new tstat)	0.5 kW (residential) and 1 kW (small C&I) [36]	15 five-hour events, plus 100 hours of minor set point adjustments per year	40% of reduced load (2 hours of pre-heating/cooling and 4-hour post-event snapback period)
Smart Water Heating (electric resistance and heat pump)	Customer impact varies by hour, based on water heating load available to curtail (0.5 kW for electric resistance and 0.13 kW for heat pumps)[37]	Daily shifting of water heating load (13 hours for electric resistance and 4 hours max for heat pump)	100% of reduced load
EV Managed Charging (home and workplace)	Customer impact varies by hour, based on average LDV fleet charging load available to curtail at home or at work. 80% of EV charging load can be reduced (0.61 kW for home and 0.01 kW for workplace)[38]	150 events per year (fleet-wide), 4 hours per event	100% of reduced load
BTM Battery (residential and commercial, BYO and new)	7.5 kW per residential customer; [39] 100 kW per C&I customer[40]; assumes benefits are attributed to exports to the grid; allows charging from the grid	100 events per year, 2 hours per event	118% of discharged energy (85% round-trip efficiency)

[35] Peak impact is defined as the potential reduction during California forecasted RA windows in 2035.

[36] Impacts based PG&E SmartAC program results. Commercial impact assumptions are informed by the relationship between residential and commercial AC programs in other jurisdictions (e.g, DPL's EmPower filing)

[37] Water heating load reduction potential based on customer water heater profiles sourced from a CEC report. The electric resistance heater has an assumed UEF of 0.96 and the heat pump has the Energy Star standard of 3.30.

[38] Vehicle charging load reduction potential is based on EV charging profiles sourced from the US Department of Energy's EVI Pro Lite tool, https://afdc.energy.gov/evi-pro-lite. These charging profiles represent, in a given hour, the average per-vehicle at-home or at-workplace charging demand for the entire electric LDV fleet. Not all EVs charge in all hours, and at a given time, some portion of the EVs will not be plugged in. A maximum of 80% of this average charging load can be reduced in any hour.

[39] BTM battery parameters are assumed to have a 2-hour duration, 5 kW max continuous output, and 10 kWh capacity. We assume an average of 1.5 batteries per participant. On average, in the U.S., residential customers have between one and two batteries. These storage parameters are roughly consistent with current models in market, for example, the Tesla Powerwall. Each participant has 7.5 kW available to dispatch fully in event hours and 15 kWh of capacity.

[40] C&I customers are assumed to have 100 kW|200 kWh of storage capacity, with 2 hours of duration based on the most prominent battery storage configurations for commercial customers. Most of the battery capacity will be behind the meter of the large C&I customer class.

Pool Pump	0.02 kW per customer[41]	15 events per year; 7 hours per event	100% of reduced load
Auto-DR (medium and large C&I)	30% of hourly load per medium C&I customer; 60% of hourly load per large C&I customer[42]	15 events per year; 5 hours per event	80% of reduced load

Costs

We develop VPP program costs based on a review of utility DR studies, existing program costs, and pilot programs in US jurisdictions.[43] Program costs considered in this study represent costs incurred by the utility to attract participants and operate each program. We take a utility perspective on costs because our analysis focuses specifically on the cost to utilities of achieving a desired level of resource adequacy. This is similar to the perspective taken in integrated resource planning, which informs utility investment decisions.

One-time costs are annualized based on a 10-year economic lifetime of participation in each program and a 7% nominal discount rate. We assume $75,000 per program start-up costs and a staffing resource assumption of four full-time equivalents compensated at $150k/yr allocated across all programs. An additional $50 per participant up-front marketing cost is included as well. These costs do not vary by program and are excluded from Table 5.

Program costs that vary by program are highlighted in Table 5. The incentives shown are adjusted for the incentive-participation relationship described above. Incremental costs of distributed energy resource management systems (DERMS) are included on a per-participant basis in Table 5 below. We model additional sensitivities around the DERMS costs.

We note that the participation incentives shown in the table below are strictly estimates based on the system benefits modeled in this study. As discussed in the Volume I report, there are several additional benefits of VPP programs that our analysis has not quantified. As such, we

41 Reduction potential is modeled based on a SDG&E pool pump demand response study. Potential is low because most customer use their pool pumps during daytime hours (before system RA windows), so there is limited load available to curtail.

42 Customer load profiles are aggregated from NREL ComStock to create class specific representative hourly profiles. Program impacts are informed by a review of California specific studies (CALMAC, CPUC).

43 Cadmus, BPA DR Potential (2018); GDS, BWL DSM potential (2020); Applied Energy Group, PacifiCorp Potential (2021); Lawrence Berkeley National Lab, DR Cost Assessment (2017); Navigant Arkansas Energy Efficiency Potential Study (2015); CEC Flexible Pool Control (2022); in addition to a review of existing program incentives in California and other jurisdictions.

anticipate that justifiable participation incentives in future program offerings are higher than shown here. Additionally, participation incentives could be structured in a variety of ways. For example, the battery program incentive could include both an up-front enrollment incentive as well as an ongoing performance incentive.

TABLE 5: BASE CASE PER-CUSTOMER PROGRAM COSTS ($2023)

Program	Customer Segment	Incremental DERMS Cost ($/part-yr)	Cost-effective incentive ($/part-yr unless noted)
Smart Thermostat (new tstat)	Residential	$6	$27.0
Smart Thermostat (BYO)	Residential	$6	$21.8
Grid-Interactive Water Heating	Residential	$11	$84.9
Heat Pump Water Heating	Residential	$2	n/a
EV Managed Charging – At Home	Residential	$15	$46.7
Storage (new battery)	Residential	$180	$268.6/kWh
Storage (BYO)	Residential	$180	$268.6/kWh
Pool Pump	Residential	$1	n/a
Storage (new battery)	All C&I	$2,400	$271.8/kWh
Storage (BYO)	All C&I	$2,400	$271.8/kWh
Smart Thermostat (new tstat)	Small C&I	$12	$61.7
Smart Thermostat (BYO)	Small C&I	$12	$50.3
Auto-DR	Medium C&I	$0[44]	$63.1/kW-yr
Auto-DR	Large C&I	$0	$63.6/kW-yr
EV Managed Charging – At Work	Residential	$1	n/a

44 No incremental DERMS costs are assigned to auto-DR programs. Given the large amount of controllable load per C&I customer, those software costs are assumed to be negligible on a per-kW basis from the utility's perspective, or otherwise rolled into the auto-DR adoption incentive cost assumption.

IV. Sensitivity Analysis Assumptions

We model several additional cases to determine the sensitivity of our findings to changes in assumptions about market conditions, electrification technology adoption, and customer enrollment. The base case serves as a central representation of future California market conditions. Each sensitivity case explores alternative individual modeling assumptions. Table 6 summarizes the key inputs for each sensitivity, with supporting details discussed below the table.

TABLE 6: SENSITIVITY INPUT SUMMARY

	Base Potential	High Potential	Low Potential
Participation	Based on observed participation potential in programs in California and other jurisdictions	Higher participation, based on program-specific range in literature review	Lower participation, based on program-specific range in literature review
Eligibility	Based on current appliance saturation forecasts for 2035	Faster electrification trajectory (e.g., EVs, heat pumps)	Slower electrification trajectory (e.g., EVs, heat pumps)
Avoided T&D Capacity Cost	T: $59.10/kW-yr, D: $24.75/kW-yr	T: $169.89/kW-yr, D: $4.73/kW-yr	T: $19.23/kW-yr, D: $28.45/kW-yr
Avoided Generation Capacity Cost	$76.20/kW-yr	$84.37/kW-yr	$36.62/kW-yr
Reserve Margin	0%	17%	Same as base case
Capacity Credit	60% for event-limited, 80% for high frequency	80% for event-limited, 90% for high frequency	40% for event-limited, 55% for high frequency
Carbon Cost	No carbon benefit	$138/ton	Same as base
Program Operation	Based on existing program parameters in CA and other jurisdictions	Longer and more frequent events	Shorter and less frequent events
DERMS Costs	$1.00–$2.00/kW-mo	~30% lower ($0.70-$1.40/kW-mo)	~30% higher ($2.00-$2.60/kW-mo)

Avoided Generation Capacity Cost

- **High potential**: $84.37/kW-yr from the California ACC model[45]

[45] https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

- **Low potential**: $36.62/kW-yr based on 2017 average California RA prices[46]

Capacity Credit

Capacity credit sensitivity cases capture uncertainty in how distributed resources will be credited with serving resource adequacy needs. All assumptions are informed by a 2021 CAISO report that evaluated ELCC value for demand response resources.[47]

- **High potential**: 80% for event-limited programs and 90% for higher-frequency programs
- **Low potential**: 40% for event-limited programs and 55% for higher frequency programs

Reserve Margin

We only model a high potential reserve margin case, which assumes a 17% planning reserve margin gross-up based on the recently adopted CPUC system RA requirement.[48] No low potential case is modeled for reserve margin since the current base case assumption does not include a reserve margin gross-up for distributed energy resources.

Avoided T&D Capacity Cost

Transmission and distribution deferral value will vary for each region within California. To capture that uncertainty in our California-wide VPP potential modeling, we model high and low avoided T&D deferral values informed by utility-specific values in the ACC. All cases use the base case hourly allocation to distribute the annual deferral values across hours of the year.

- **High potential:** SDG&E estimates from the 2023 ACC model ($169.89/kW-yr for transmission and $4.73/kW-yr for distribution). SDG&E transmission losses of 7.1% and distribution losses of 4.3% are also from the ACC.[49] We note that even higher T&D investment deferral benefits may be achieved when targeting specific high-cost projects on the system; our assumed values represent averages across a relatively broad geographic area.

46 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2017rareport.pdf

47 https://www.caiso.com/Documents/Presentation-ELCCStudyResults-DemandResponseResources-Jun24-2021.pdf

48 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage

49 https://www.ethree.com/public_proceedings/energy-efficiency-calculator/

- **Low potential:** SCE estimates from the 2023 ACC model ($19.23/kW-yr for transmission and $28.45/kW-yr for distribution). SCE transmission losses of 5.4% and distribution losses of 2.2% are also from the ACC. [50]

Carbon Cost

We only model a high-value carbon cost sensitivity because the base case assigns no direct carbon emissions cost to electricity production. The hourly emissions profile is a load-weighted average of the NP-15 and SP-15 2035 hourly emissions profile from the 2023 ACC model. The high-value case assumes a carbon price of $138/ton based on the Preferred System Plan carbon scenario from the ACC.[51]

Eligibility

The pace at which customers adopt electrification appliances and technologies will impact their eligibility to participate in our modeled VPP programs. We account for the uncertainty around customer adoption by modeling a high-value sensitivity case that assumes faster adoption of electrified end-use technologies such as heat pumps and electric vehicles and a low-value case that assumes slower adoption, as shown in Table 7.

[50] Ibid.

[51] Ibid.

TABLE 7: ELIGIBILITY SENSITIVITY CASE ASSUMPTIONS (% OF CUSTOMER CLASS)

Program	Customer Segment	Base	High Potential	Low Potential
Smart Thermostat (new tstat)	Residential	36%	33%[52]	39%
Smart Thermostat (BYO)	Residential	28%	34%	23%
Grid-Interactive Water Heating	Residential	6%	6%	6%
Heat Pump Water Heating	Residential	37%	40%	24%
EV Managed Charging – At Home	Residential	49%	77%	25%
Storage (new battery)	Residential	98%	98%	98%
Storage (BYO)	Residential	2%	2%	2%
Pool Pump	Residential	9%	9%	9%
Storage (new battery)	All C&I	82%	82%	82%
Storage (BYO)	All C&I	1%	1%	1%
Smart Thermostat (new tstat)	Small C&I	57%	51%	62%
Smart Thermostat (BYO)	Small C&I	18%	24%	13%
Auto-DR	Medium C&I	100%	100%	100%
Auto-DR	Large C&I	100%	100%	100%
EV Managed Charging – At Work	Residential	49%	77%	25%

[52] Since increased customer electrification (e.g., heat pump adoption) drives High Potential case assumptions, we see an increase in forecasted smart thermostat adoption, absent of VPP program incentives. This leaves a *smaller* pool of customers that are eligible for the new smart thermostat program because eligible customers are not assumed to adopt a smart thermostat before enrolling in a VPP program. The same logic applied for the BYO and new commercial smart thermostat program.

Participation

The participation values in Table 8 have been adjusted to account for program cost-effectiveness as previously described.

TABLE 8: PARTICIPATION SENSITIVITIES (% OF ELIGIBLE CUSTOMERS)

Program	Customer Segment	Base	High Potential	Low Potential
Smart Thermostat (new tstat)	Residential	26%	48%	17%
Smart Thermostat (BYO)	Residential	29%	54%	20%
Grid-Interactive Water Heating	Residential	41%	75%	27%
Heat Pump Water Heating	Residential	0%[53]	15%	0%
EV Managed Charging – At Home	Residential	26%	41%	10%
Storage (new battery)	Residential		See note[54]	
Storage (BYO)	Residential		See note	
Pool Pump	Residential	0%	0%	0%
Storage (new battery)	All C&I		See note	
Storage (BYO)	All C&I		See note	
Smart Thermostat (new tstat)	Small C&I	21%	34%	9%
Smart Thermostat (BYO)	Small C&I	23%	37%	9%
Auto-DR	Medium C&I	21%	32%	11%
Auto-DR	Large C&I	21%	32%	11%
EV Managed Charging – At Work	Residential	0%	30%	5%

53 Programs with 0% participation are not cost-effective based on the specific modeling assumptions in this study.

54 As described in the above sections, residential and commercial battery participation assumptions are tied to Green Mountain Power's behind-the-meter storage adoption forecast. In the base case we assume 1% of all residential customers will adopt and enroll by 2035, which includes both the BYO and new storage program. We assume 1.5% for the high case and 0.5% for the low case. For the commercial and industrial customers, we anchor our 0.2% participation on the Green Mountain Power residential program participation assumptions compared to the residential adoption forecasted by the IEPR, absent any programs. We assume 0.6% of all C&I customers participate in the high case and 0.1% participate in the low case. https://greenmountainpower.com/wp-content/uploads/2021/12/2021-Integrated-Resource-Plan.pdf

Program Operations

The duration and frequency of demand response events can vary greatly based on customer preferences. Some customers would be more willing to have their end-use devices controlled on a longer and more frequent basis than others. To capture the uncertainty around customer performance, we include a high and low scenario that tests the frequency and duration of called events on overall potential. Table 9 below shows the high and low-value sensitivity assumptions by program.

TABLE 9: PROGRAM OPERATIONS SENSITIVITIES

Program	Base	High Potential	Low Potential
Smart Thermostat (BYO and new tstat)	15 five-hour events, plus 100 hours of minor set point adjustments per year	20 five-hour events, plus 100 hours of minor set point adjustments per year	10 three-hour events, plus 100 hours of minor set point adjustments per year
Smart Water Heating (electric resistance and heat pump)	Daily shifting of water heating load (13 hours for electric resistance and 4 hours max for heat pump)	Daily shifting of water heating load (16 hours for electric resistance and 7 hours max for heat pump)	200 days of shifting of water heating load (7 hours for electric resistance and 3 hours max for heat pump)
EV Managed Charging (home and workplace)	150 events per year, 4 hours per event	200 events per year, 6 hours per event	100 events per year, 3 hours per event
BTM Battery (residential and commercial, BYO and new)[55]	100 events per year, 2 hours per event	100 events per year, 2 hours per event	100 events per year, 2 hours per event
Pool Pump	15 events per year; 7 hours per event	30 events per year; 10 hours per event	5 events per year; 4 hours per event
Auto-DR (Medium and large C&I)	15 events per year; 5 hours per event	20 events per year; 6 hours per event	10 events per year; 4 hours per event

DERMS Costs

A significant portion of the per-participant program implementation costs are per device DERMS costs that cover the third-party software platform used to control load. DERMS companies will vary these costs by device and utility subscription plan, often tailoring costs to the economics of specific program offerings. We model a high potential case (with lower

55 Note the storage battery operations do not vary in this sensitivity.

DERMS costs) and a low potential case (with higher DERMS costs) to capture variability in DERMS pricing strategies as the market evolves between now and 2035. DERMS costs and sensitivities are informed by a survey of vendor interviews.

- **High potential** (low DERMS cost): 30% lower than the base case, around $0.70–$1.40/kW-mo.
- **Low potential** (high DERMS cost): 30% higher than the base case, around $2.00–$2.60/kW-mo.

V. The *FLEX* Model

The Brattle Group's *FLEX* model was developed to quantify the potential impacts, costs, and benefits of VPP programs. The *FLEX* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging VPP programs, which not only reduce system peak demand but also provide around-the-clock load management opportunities.

The *FLEX* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the US and internationally but incorporates a number of differentiating features that allow for a more robust evaluation of VPP programs:

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the C&I sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospitals or universities). Load curtailment capability is further calibrated to the utility's experience with DR and VPP programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).
- **Sophisticated VPP program dispatch:** VPP program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), *FLEX* includes an hourly profile of load interruption capability for each program. For instance, for a home EV charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** VPP programs have the potential to simultaneously provide multiple benefits. For instance, a VPP program that is dispatched to reduce the system peak and, therefore, avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. *FLEX* accounts for these tradeoffs in its VPP dispatch algorithm. VPP program operations are simulated to maximize total benefits across multiple value streams while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to VPP programs without accounting for these tradeoffs, thus double-counting benefits.
- **Industry-validated program costs:** VPP program costs are based on a detailed review of current VPP offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.