



The Affordability Advantage: How Virtual Power Plants Can Alleviate Household Electricity Bill Pressure

VOLUME I: SUMMARY REPORT

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Notice

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We would like to thank the Everyday Electric team for their invaluable leadership and feedback throughout this study, including Will Baker, Rizwan Naveed, and Casey Sinnwell. We would also like to thank Amy Heart and Kyle Wallace of Sunrun and Jordan Graham of Tesla for their insights on OEM-led enrollment strategies. Finally, we are grateful for the analytical contributions and review of this study from our Brattle colleagues Kate Peters, Akhilesh Ramakrishnan, and Sanem Sergici.

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Section I: **Summary**

Background

The purpose of this study is to analyze the near-term affordability benefits that virtual power plants (VPPs) can provide to residential customers when scaled through a new approach to customer engagement.

Energy affordability has emerged as a widespread national challenge

- The average U.S. residential electricity rate increased 33% between 2019 and 2025 (in nominal terms). Growth has recently outpaced inflation.
- The increased cost of power systems equipment is a major driver. Recent doubling of natural gas-fired generation capacity costs is an acute near-term concern; demand continues to outstrip production due to supply chain shortages.

Virtual Power Plants (VPPs) are uniquely positioned to help mitigate the problem. They are:

- Cost-effective, by leveraging flexibility of existing assets already deployed at the grid edge (e.g., connected thermostats, EVs, batteries).
- Directly beneficial to households, by paying participants for providing grid services, rather than generators.
- Fast to scale, without lengthy interconnection delays or long equipment lead times.

OEM-led enrollment strategies can help VPPs reach scale, maximizing affordability impacts

- By leveraging capabilities already built into customers' devices, distributed energy resource (DER) providers can streamline enrollment and improve customer engagement to grow VPP participation well beyond historically observed levels.

FEATURES OF THIS STUDY

- ✓ Specific focus on residential households
- ✓ Accounts for new evidence on the market-expanding effect of OEM-led enrollment
- ✓ Leverages load impact data from over 6 million existing DERs
- ✓ Attributes proven capacity value to VPPs consistent with methods currently used by market operators and utility system planners
- ✓ Accounts for practical limitations on opportunity to reduce distribution system costs
- ✓ Focuses on near-term (5-year) deployment opportunities

The Modeled VPP Could Reach “Utility Scale” Within Five Years

We modeled residential VPP development in a nationally representative, 1-million residential customer utility. Through innovation in consumer engagement and enrollment, the VPP could scale to over 300 MW within the next five years—4% of the utility’s system peak demand and equivalent in size to a natural gas power plant.

We forecasted adoption and enrollment of behind-the-meter (BTM) battery storage, EV managed charging and two types of smart thermostat customers: smart thermostat customers with average levels of load reduction, and “high-impact” customers who are more responsive and provide larger load reductions in exchange for higher performance payments.

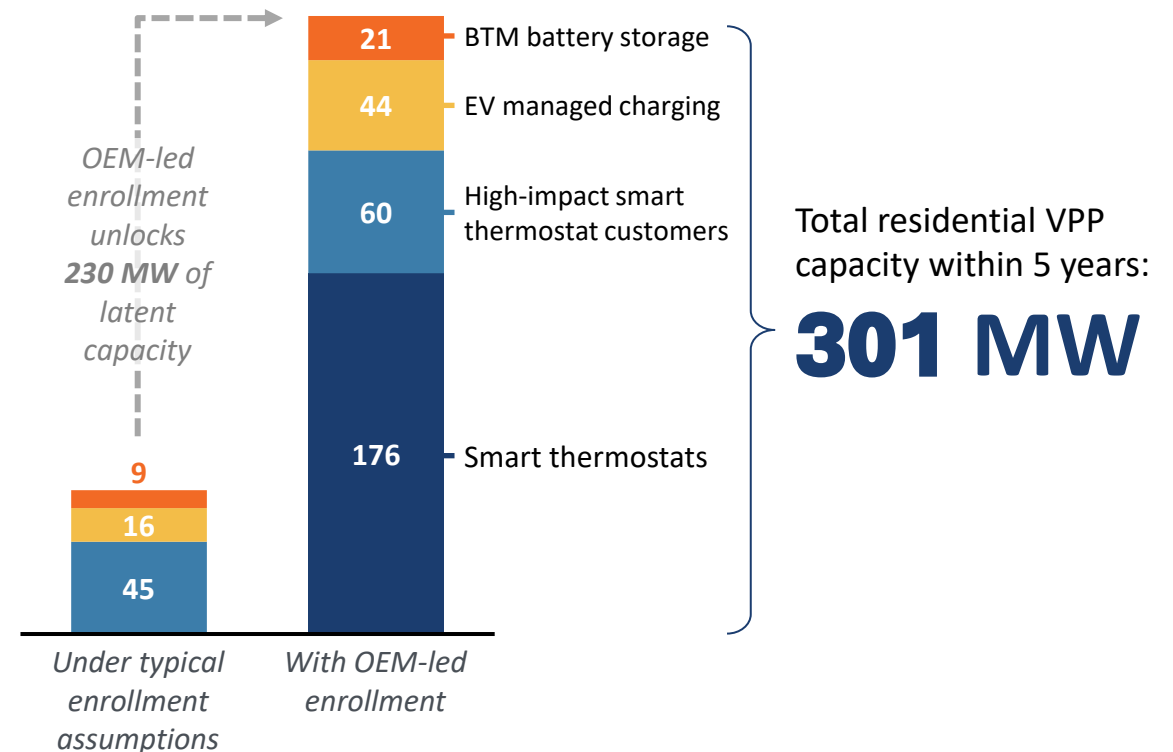
The VPP’s growth is facilitated through **OEM-led enrollment**—strategies by DER providers that leverage existing capabilities in customers’ devices to remove barriers to enrollment, without requiring additional engagement with the utility.

Case Studies: OEM-Led Enrollment in Action

Everyday Electric increased VPP enrollment from smart thermostats by a factor of four through frictionless enrollment processes and load-shifting that is personalized to customers’ preferences. Less than four percent of customers opt out of DR events.

Sunrun and Tesla auto-enrolled battery customers in Puerto Rico’s battery VPP program, increasing participation sevenfold in one year. Despite having the option to opt out both before and during the program, 93% of customers joined the program and over 98% of those remain enrolled.

Installed VPP Capacity (MW)
Representative 1 million customer utility



The VPP Produces Significant Financial Benefits for Consumers

The total value created by the VPP is over 7 times the cost of enabling it, and the vast majority of this value goes to consumers.

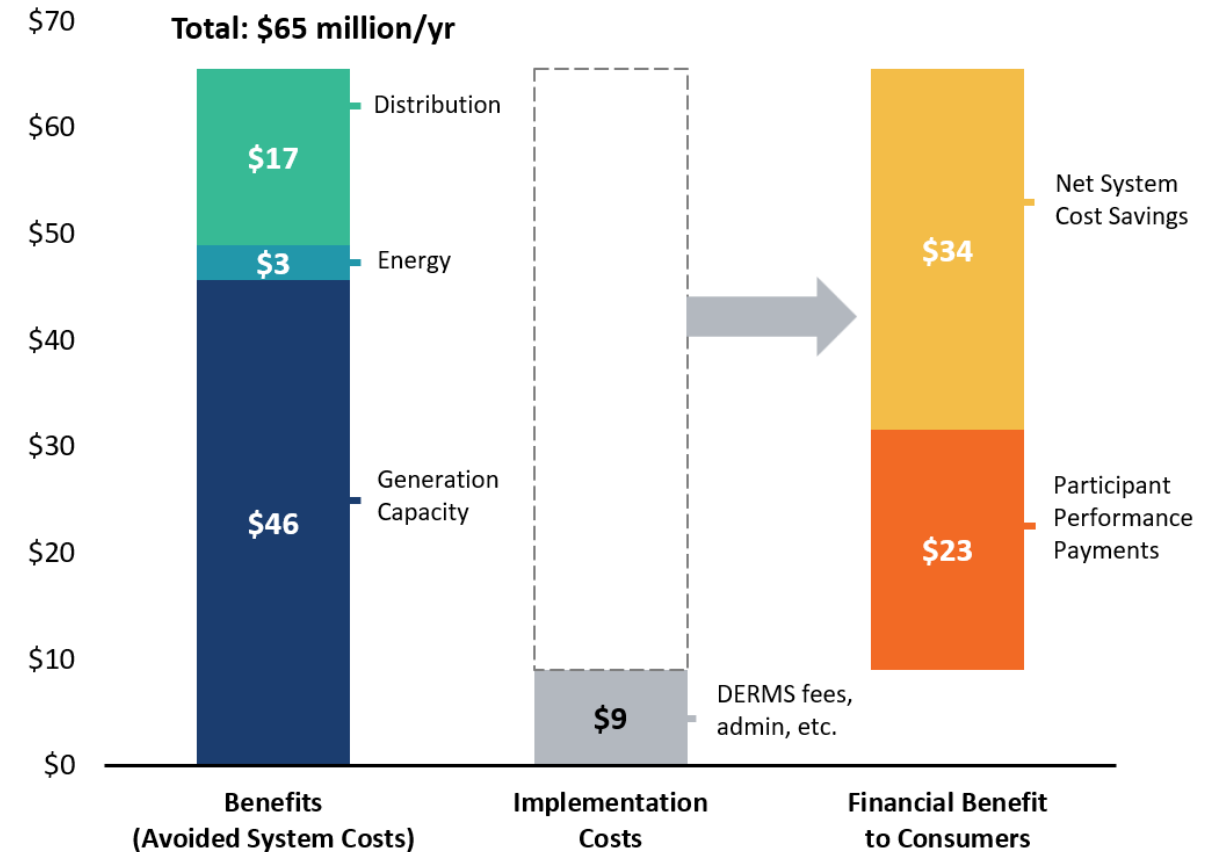
In its first year of operation, the VPP avoids \$65 million per year in capacity, energy, and distribution upgrade costs. Delivering this value requires just \$9 million per year in implementation costs (e.g., marketing and administration costs, and incremental device integration / software fees).

Further, the primary “cost” of the VPP is not really a cost at all, but a performance payment to participating households. At the performance payments assumed in this study, the utility would pay participating VPP households roughly \$23 million per year instead of writing checks to power developers.

The result is that most of the value created by the VPP goes to consumers, either directly through participant performance payments or indirectly through net system cost savings that are shared across all ratepayers.

Note: Analysis assumes average VPP performance payment of \$75/kW-yr. This value is an average—performance payments vary across different technologies within the VPP. Totals may not sum due to rounding. See Technical Appendix for further detail.

Annual Value of VPP Portfolio (\$2026 million/yr)



The VPP Cuts Expected Household Electricity Bill Increases in Half

By the time the VPP reaches scale (approximately five years), it reduces bill increases for average households by more than half. Bill increases are almost completely offset for VPP participants in inflation-adjusted terms.

1

Avg. increase in annual bill after 5 years without VPP

\$98 (2026 dollars)

Based on recent trends, we consider a forward-looking scenario in which, absent the deployment of a VPP, retail electricity bills continue to grow at a pace that is 1% per year faster than inflation. At this rate of growth over 5 years, average annual household bills will be nearly \$100 greater than today in inflation-adjusted terms.

2

Bill savings with VPP for avg. household

-\$56 (2026 dollars)

The net value of the VPP (avoided resource costs net of performance payments and implementation costs) flows through to residential rates, saving all households money on their electricity bill. Since a significant share of the customer base participates in the VPP, customers see a sizable payment on average.

3

Bill savings with VPP for non-participating households

-\$34 (2026 dollars)

Non-participating households do not receive performance payments, but still avoid a third of the bill increase through net system cost savings that flow through to all ratepayers.

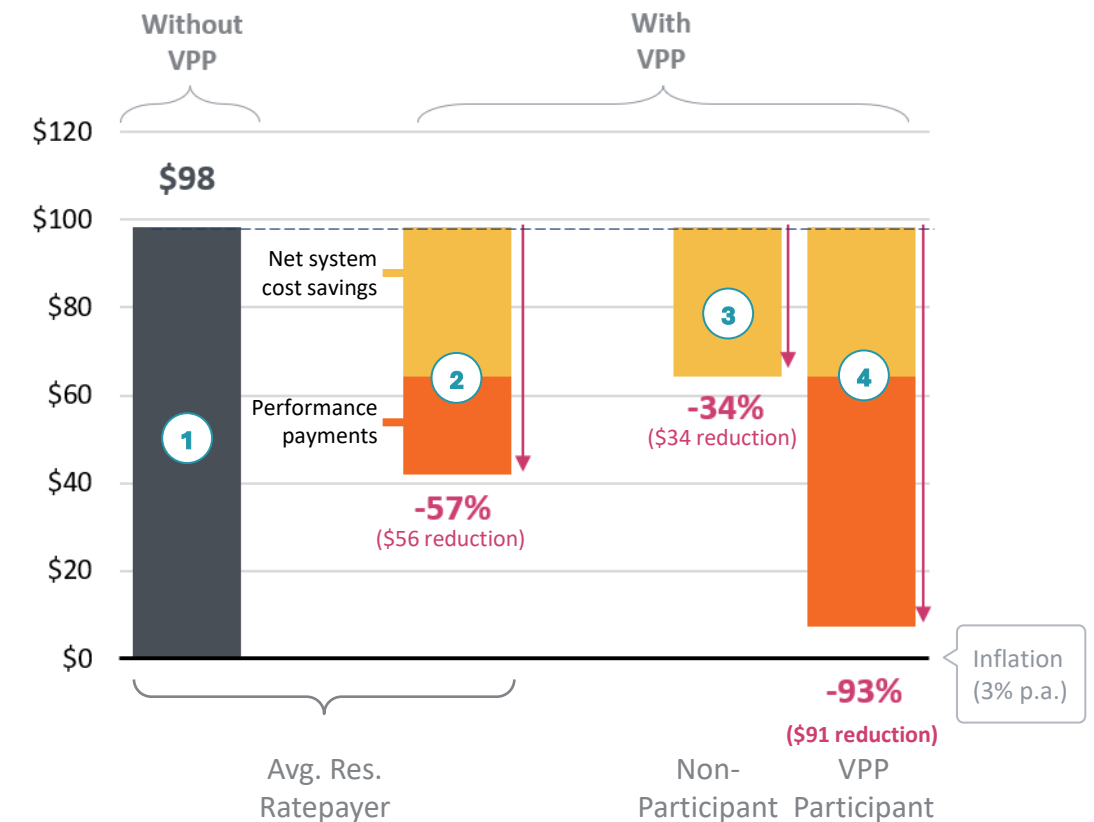
4

Bill savings with VPP for avg. participants

-\$91 (2026 dollars)

With the addition of performance payments, bill growth for participating households is almost entirely offset in inflation-adjusted terms.

Change in Bill After Five Years, Without and With VPP (\$2026/yr)

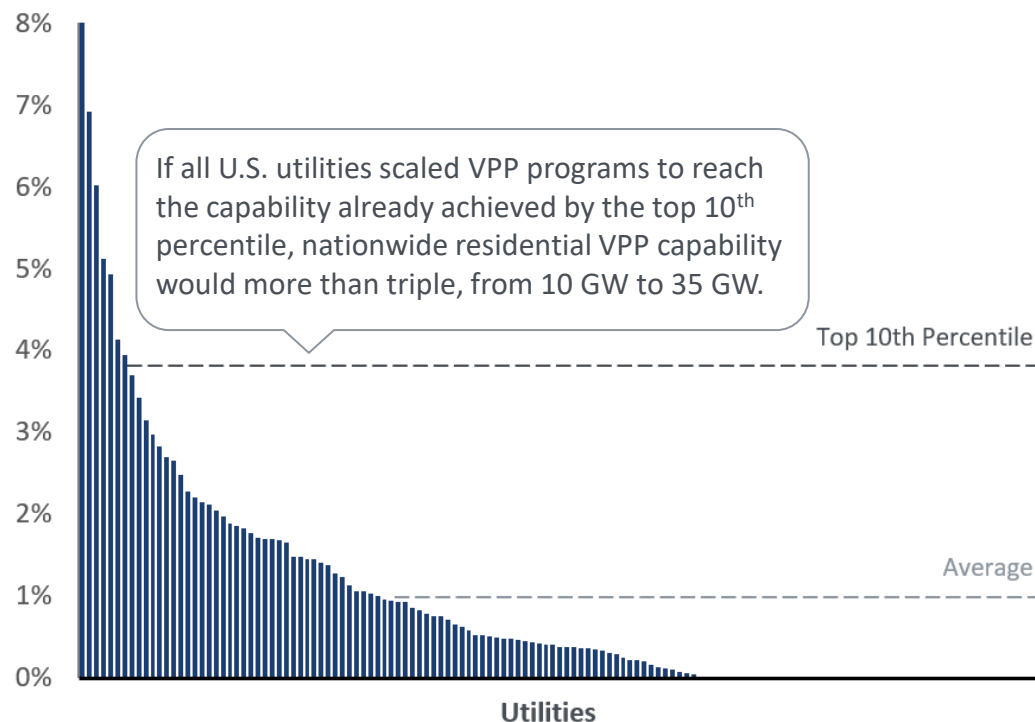


Note: To maintain this relative level of bill relief in later years, the VPP would need to continue to scale beyond the level modeled in this study.

Achieving “Utility-Scale” VPPs through Enhanced Enrollment

If all utilities were to achieve a 4% system peak reduction from residential VPPs, national capability would more than triple, from 10 GW to 35 GW, generating an additional \$4–7 billion per year in financial benefits for households.

U.S. Utility Residential DR Capability, as % of System Peak Demand



Notes: Based on EIA-861 data. Capability is 2022-2024 average. For simplicity, results are shown for utilities with at least 1,000 MW of peak demand. Y-axis values stop at 8% but one utility in the dataset reports 16% capability. Averages and percentiles are load-weighted.

For the near-term affordability benefits of VPPs to materialize at the level described in this study, VPPs will need to scale quickly and significantly. National data support the achievability of this outcome.

Across U.S. utilities, residential demand response (DR) capability currently represents 1.1% of system peak demand on average. By comparison, the 4% system peak impact modeled in our analysis equates roughly to the top 10th percentile of utilities. **If all utilities were to achieve a 4% system peak reduction, the national capability would more than triple, from 10 GW to 35 GW.** While many factors will drive differences in the achievable level of residential VPP capability across utilities, this demonstrates significant room for growth on a national scale.

The path to 4% does not necessarily require waiting for a new generation of devices to be deployed. A substantial pool of flexible capacity already exists in connected thermostats and other devices in homes today, creating an opportunity for utilities to focus on enrolling and activating existing assets.

Based on the results in this study, scaling national residential demand flexibility from 10 GW to 35 GW would generate over **\$4–7 billion per year** in incremental financial benefits for households. Focusing on activating existing assets offers an opportunity to generate these savings in the near term while consumer bill pressure is elevated.

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Section II: **Introduction**

This Study Evaluates the Role of VPPs in Addressing Affordability Concerns

Introduction

Until recently, residential electricity prices across most of the U.S. [increased at or below](#) the rate of inflation. While the cost of an essential service such as electricity will always be an important policy consideration, this represented a broadly sustainable and affordable trajectory.

That trajectory has changed. Over the past five years, electricity prices have risen faster than an already elevated rate of inflation, increasing household electricity bills and putting renewed pressure on utilities, regulators, and policymakers to address affordability.

A key driver of these increases is the rising cost of power system infrastructure. For example, the cost of new natural gas generating capacity has roughly doubled in the past four years, driven by supply chain constraints and unexpectedly rapid demand growth. These pressures have created an urgent need for alternative solutions that can be deployed quickly, at scale, and at lower cost.

Study Purpose

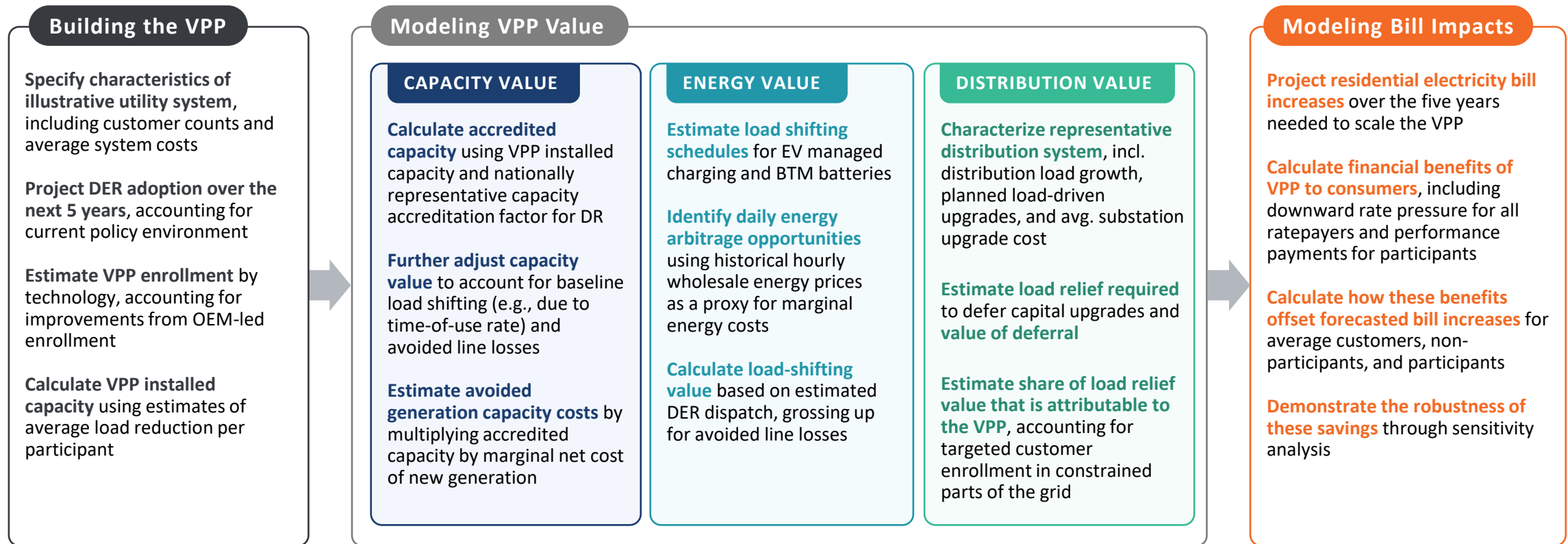
The purpose of this study is to analyze the role virtual power plants (VPPs) could play in returning electricity bill growth to historically sustainable levels. Prior studies have quantified the cost-competitiveness of VPPs as a resource, but have not specifically addressed the extent to which expanded VPP deployment can mitigate near-term U.S. household electricity bill growth. As coordinated aggregations of flexible household technologies such as thermostats, batteries, and EVs, VPPs are uniquely positioned to provide affordability benefits to residential customers both by putting downward pressure on rates and by paying participants for the services they provide to the grid.

Features of the Analysis

- **Specific focus on households**, in terms of VPP offering (thermostats, EVs, batteries) and bill impacts.
- **Accounts for new evidence** on the market-expanding effect of an OEM-led approach to VPP enrollment
- **Leverages load impact data from over 6 million existing DERs** to ensure realistic representation of VPP operational performance
- **Attributes proven capacity value to VPPs** consistent with methods currently used by market operators and utility system planners
- **Accounts for practical limitations on the opportunity to reduce distribution system costs** (i.e., deferral opportunities exist only in certain locations of the system, and are only temporarily deferrable)
- **Focuses on deployment opportunities over the next 5 years**, to inform near-term actions that can be taken to enable beneficial outcomes

This Study's Approach

For an illustrative, 1-million residential customer utility, we (1) estimate the scale a VPP could reach within the next five years using OEM-led enrollment strategies, (2) calculate the value the VPP can provide, and (3) show how this value translates into affordability benefits for ratepayers and participants.



Note: See Volume II: Technical Appendix for additional detail on modeling framework, assumptions, and sources.

The top half of the image features a background of a repeating geometric pattern in various shades of blue. The pattern consists of interlocking triangles and squares, creating a textured, mosaic-like effect.

Section III: **How VPPs Address Challenges of Today's Grid**

VPPs are Uniquely Positioned to Address Current Challenges

VPPs are among the fastest, cleanest, and least expensive forms of new capacity.

	Virtual Power Plant (HVAC, batteries, EVs)	Gas Peaker (Combustion Turbine)	Utility-scale Battery (4-hr)	Standalone Solar
Current utility investment cost	 \$500-1,000/kW	 \$2,000/kW or higher	 \$1,750/kW	 \$1,400-1,600/kW
Effectiveness as capacity resource	 Depends on technology composition and dispatch limitations	 Available other than maintenance and fuel shortages	 Energy-limited, tradeoffs with other value streams	 Intermittent, modest contribution at peak times
Time to deploy	 1-3 years; no generator interconnection process	 5-10 years; supply chain constraints, interconnection delays	 3-7 years; possible interconnection delays	 3-7 years; possible interconnection delays
GHG emissions impact	 Depends on technology composition and local generation mix	 Burns gas at high heat rate; runs relatively infrequently	 Depends on local generation mix; cycling efficiency losses	 Displaces GHG-emitting resources
Additional system value (varies by market)	Distribution investment deferral and energy	Energy and ancillary services	Energy and ancillary services	Energy

Note: Table is broadly indicative of relative attractiveness of each resource option. The attractiveness of resource types will vary depending on jurisdiction, market conditions, and other factors. See the following page and Volume II: Technical Appendix for more detail on costs. "Time-to-online" data informed by LBNL's 2026 Queued Up [report](#) (p. 51).



Inflated Generation Capacity Costs Require Near-Term Affordability Solutions

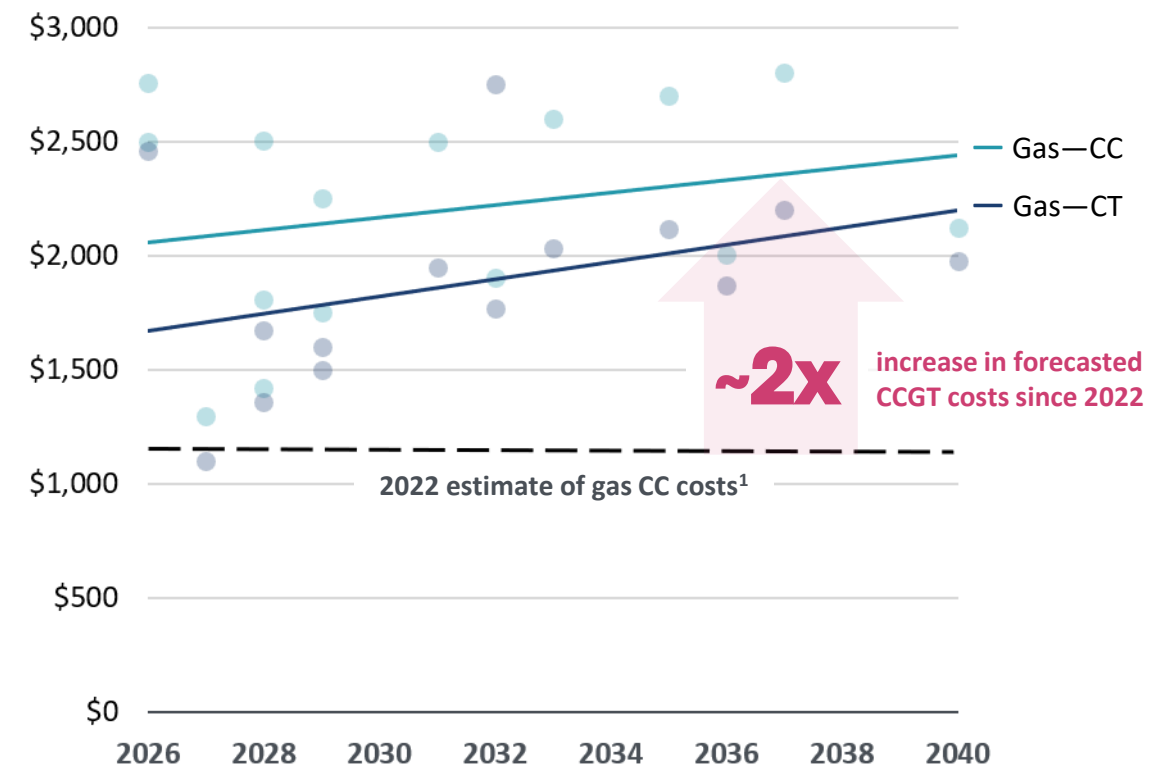
Gas turbines are currently experiencing significant supply chain constraints, driving near-term capital cost forecasts to multiples higher than historical levels.

Unanticipated load growth has created shortages in gas generating equipment, resulting in extremely long lead times and sharp increases in equipment costs. Recent forecasts indicate that this elevated price environment for gas generation is likely to persist into the 2030s, as shown in the figure to the right.

With gas generation typically used as the reference marginal capacity resource in system planning, these high prices present a risk of significant costs being passed on to consumers as generation is built to meet load growth. VPPs can provide capacity at a fraction of this cost, representing a significant opportunity to deliver affordability benefits to consumers by avoiding these high costs.

Our study accounts for the impact of elevated gas equipment costs, adopting an associated marginal cost of generation capacity of \$200/kW-yr (2026 dollars). The high uncertainty around the current price environment and the upward trajectory of price forecasts over recent months means that this may be a conservative estimate of short-term costs; we evaluate higher and lower values through sensitivity analysis. See the Technical Appendix for further explanation of our assumptions.

Recent Forecasts of Gas Turbine Installed Capital Costs (\$/kW)



See Volume II: Technical Appendix for more detail on costs.

¹ Brattle (2022), [PJM 2026/27 CONE Study](#)

Evaluating VPP Benefits for a Representative Utility

To evaluate the affordability benefits of VPPs, we defined a representative utility with 1 million residential customers as the basis for our analysis, and benchmarked key inputs against utilities in a range of jurisdictions.

Key Utility Characteristics

Residential customer count	1,000,000
Residential peak coincident demand	3,500 MW
Total coincident peak summer demand	7,000 MW
Marginal cost of new generation capacity	\$200/kW-yr
Average residential retail electricity rate	16.5 cents/kWh
Share of distribution substations/feeders with load-driven upgrade requirement over 5 years	7%

The illustrative utility is based on nationally representative characteristics. Where regional assumptions or data were needed, we used the characteristics of Midwestern utilities/markets. To provide a sense of scale, similarly sized investor-owned utilities include Ameren Missouri and Duke Energy Indiana. See Technical Appendix for detailed descriptions of utility definition and DER adoption assumptions.

DER Adoption Statistics: 5-Year Outlook

Smart thermostat adoption



60%
(of households with central AC)

Latest figures indicate that 36% of homes with central AC already have smart thermostats today; Everyday Electric projects significant growth in the next ~5 years

Rooftop solar penetration



9.5%
(of households)

Below recent 5-yr projections from strong Midwestern solar markets (e.g., 12% in IL), to account for OBBBA-related headwinds

EV share of light-duty vehicle stock



11%

Lower than the 5-yr projected US average (13%) to distinguish from strong/outlier EV markets (e.g., CA); forecasted growth is consistent with transportation electrification-oriented states, while accounting for OBBBA-related headwinds

Storage attachment rate



14%
(of rooftop solar installations)

2025 saw significant increases in storage attachment rates (e.g., 17% in IL). This rate assumes some continued growth in the face of electricity rate pressure, but is below the 2025 U.S. average excluding CA (17%) and assumes no net-metering tariff reform (which would likely increase attachment)

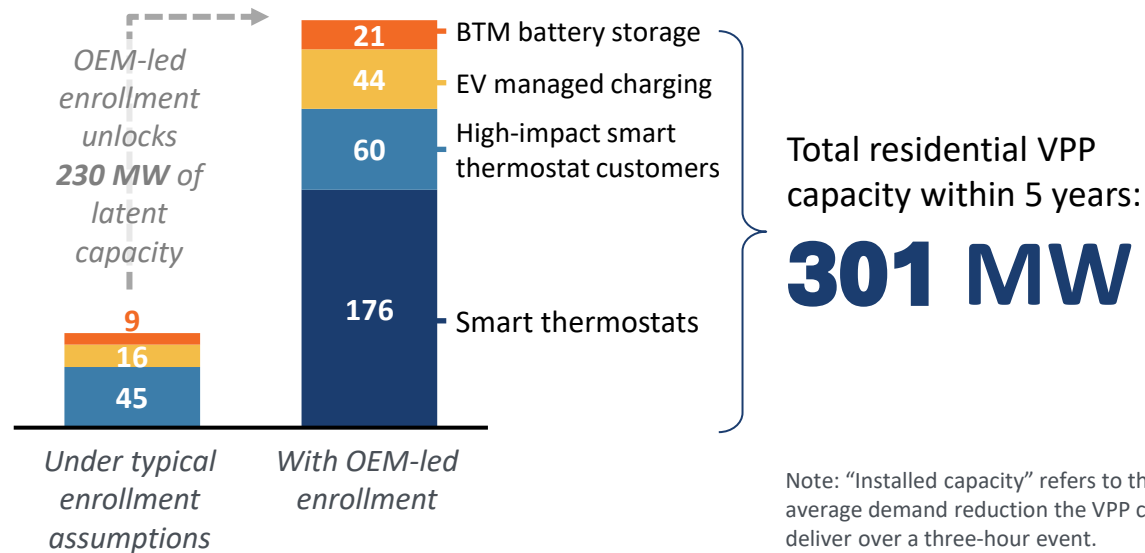
The Modeled VPP Could Reach “Utility Scale” Within Five Years

The VPP grows to over 300 MW. This represents 9% of the representative utility’s residential peak demand (3,500 MW) and 4% of total coincident peak demand (7,000 MW).

We forecasted adoption and enrollment of BTM battery storage, EV managed charging and two types of smart thermostat customers: smart thermostat customers with average levels of load reduction, and “high-impact” customers who are more price responsive and provide larger load reductions in exchange for higher performance payments.

Installed VPP Capacity (MW)

Representative 1 million customer utility



Enrollment Levels Driving Scale

Smart thermostat participation



37% of residential customers

Everyday Electric’s OEM-led enrollment strategies have seen significant enrollment rates among both new and existing smart thermostat customers (see slide 28)

BTM battery participation



0.5% of residential customers

Significant participation has been observed among emerging BTM battery VPP programs (e.g., MA/RI ConnectedSolutions); OEM-led enrollment strategies have yielded 90%+ enrollment rates (e.g., Sunrun default enrollment in Puerto Rico)

EV managed charging participation



6% of residential customers

25%+ participation among EV owners exists in mature passive EV managed charging programs (e.g., ConEd SmartCharge NY), with recent active programs/pilots achieving 7–10% enrollment among EV owners in a few years (e.g., PGE, DTE, PSE); OEM-led enrollment is expected to further boost participation

Planning-Grade Capacity

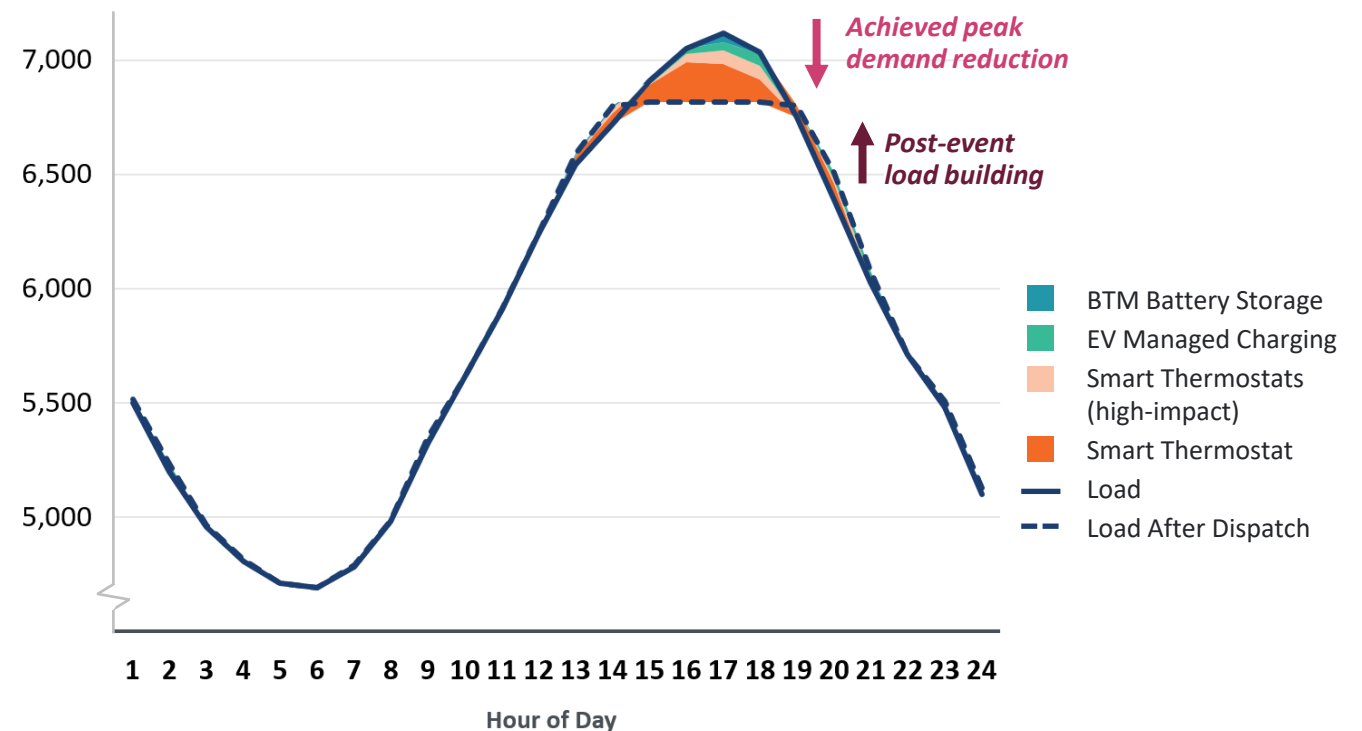
In addition to reaching sufficient scale, system operators need to trust that the VPP will perform as expected and fully incorporate that performance into planning decisions.

Our analysis assigned capacity credit to the VPP at a level observed in other markets and jurisdictions. While system conditions and methods vary, capacity credit generally ranges from 60% to nearly 100% of nameplate capacity (see Technical Appendix). Our study uses 75% as a base assumption and a lower credit for participants that already shift their load in response to time-of-use rates, resulting in an effective VPP-wide capacity credit of 70%. In other words, 301 MW of “nameplate” VPP capacity is assumed to have 211 MW of capacity value on the system.

System reliability analysis supports this assumption. Using the demonstrated performance characteristics of each technology in the VPP, we simulated its dispatch against 10 years of historical hourly system load data for a midwestern utility. **Across 10 years of historical weather and load conditions, the VPP achieved 228 MW of system peak demand reduction on average, equating to a 76% capacity credit.**

The figure at right illustrates how dispatch of the VPP reduces demand on the peak day of a representative year. See Volume II: Technical Appendix for further detail on this modeling.

VPP Dispatch on Peak Net Load Day (MW)



Note: EV managed charging and BTM battery storage shift all curtailed load into earlier and later hours. Smart thermostats reduce cooling demand, with some pre-cooling and post-event snapback. In this example, this pre- and post-event “load building” is spread across several hours on a day where electricity demand rises and falls steeply, which visually appears to result in modest increases in net load in these hours.

Avoided Capacity and Distribution Costs Drive Value

The VPP produces over \$200/kW-yr of value, primarily by avoiding generation capacity costs and providing targeted distribution load relief.

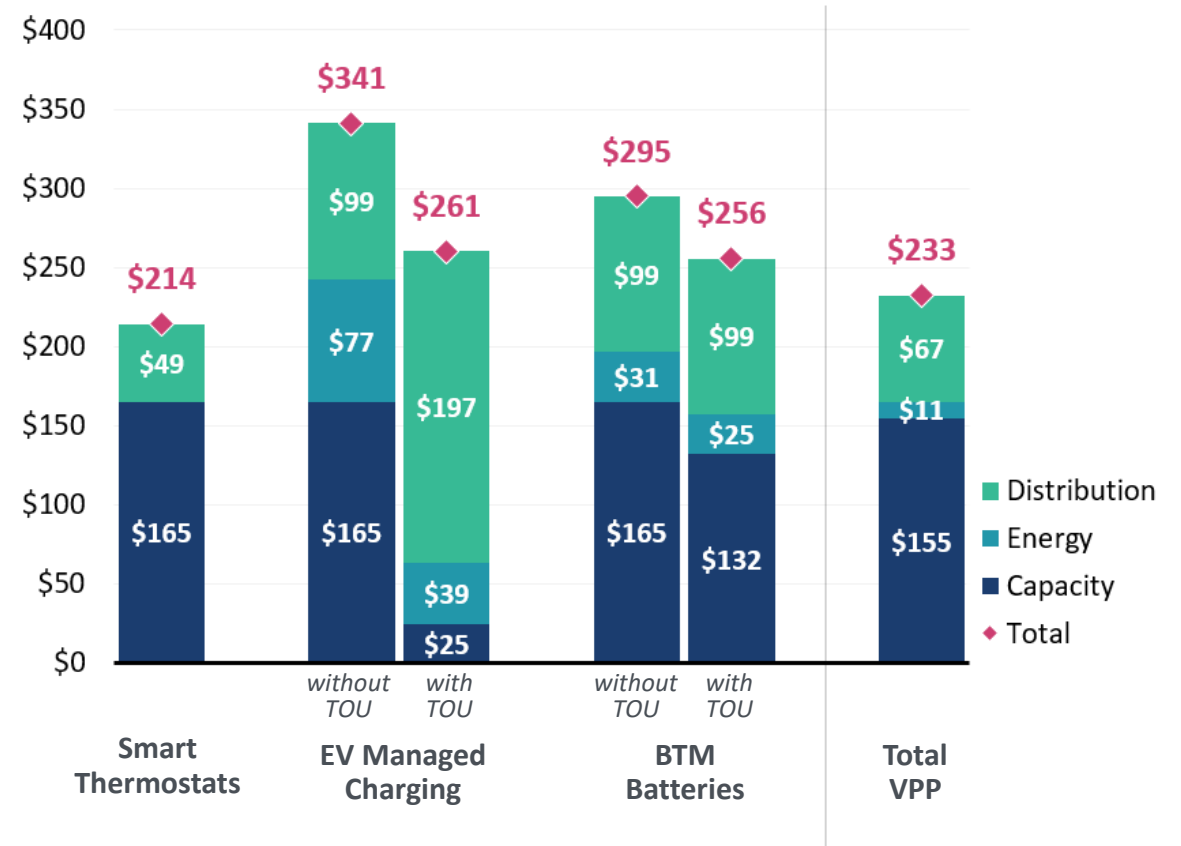
The “value stack” of each technology in the VPP varies depending on its operational characteristics. Since EV and battery customers on time-of-use (TOU) rates are likely to already shift their load in response to the price signals in their rate, we model separate value stacks for these customers.¹

Distribution value is provided by DERs contributing to load relief required to defer capital upgrades on the distribution system. We estimate the share of the grid that is constrained, and assume the VPP targets enrollment toward customers on these parts of the grid in order to maximize the opportunity to contribute to such deferrals.

The pathway to monetizing the VPP’s value will vary by utility, but **each value stream represents fundamental costs that can be avoided regardless of market structure**. Vertically integrated utilities can directly offset their generation capacity and energy costs; in restructured markets, these benefits show up as lower capacity obligations and reduced wholesale energy procurement costs.

1. For some technologies, capacity and energy value is limited depending on whether the customer is enrolled in a TOU rate, since these customers likely already shift their load. While EV customers on TOU rates offer less capacity and energy value, they may exacerbate distribution system constraints through charging “snapback”, so enrolling them in VPPs increases distribution value—we assume that these customers offer 15% of the capacity value, 50% of the energy value, and twice the distribution value as EV customers on regular rates, based on findings from Brattle’s 2026 EV Managed Charging [report](#) with EnergyHub. We assume batteries on TOU rates generate 80% of the energy and capacity value as non-TOU batteries.

Levelized Value of VPP Portfolio Over First Five Years
(\$2026/kW-yr)



The VPP Produces Significant Financial Benefits for Consumers

The total value created by the VPP is over 7 times the cost of enabling it, and the vast majority of this value goes to consumers.

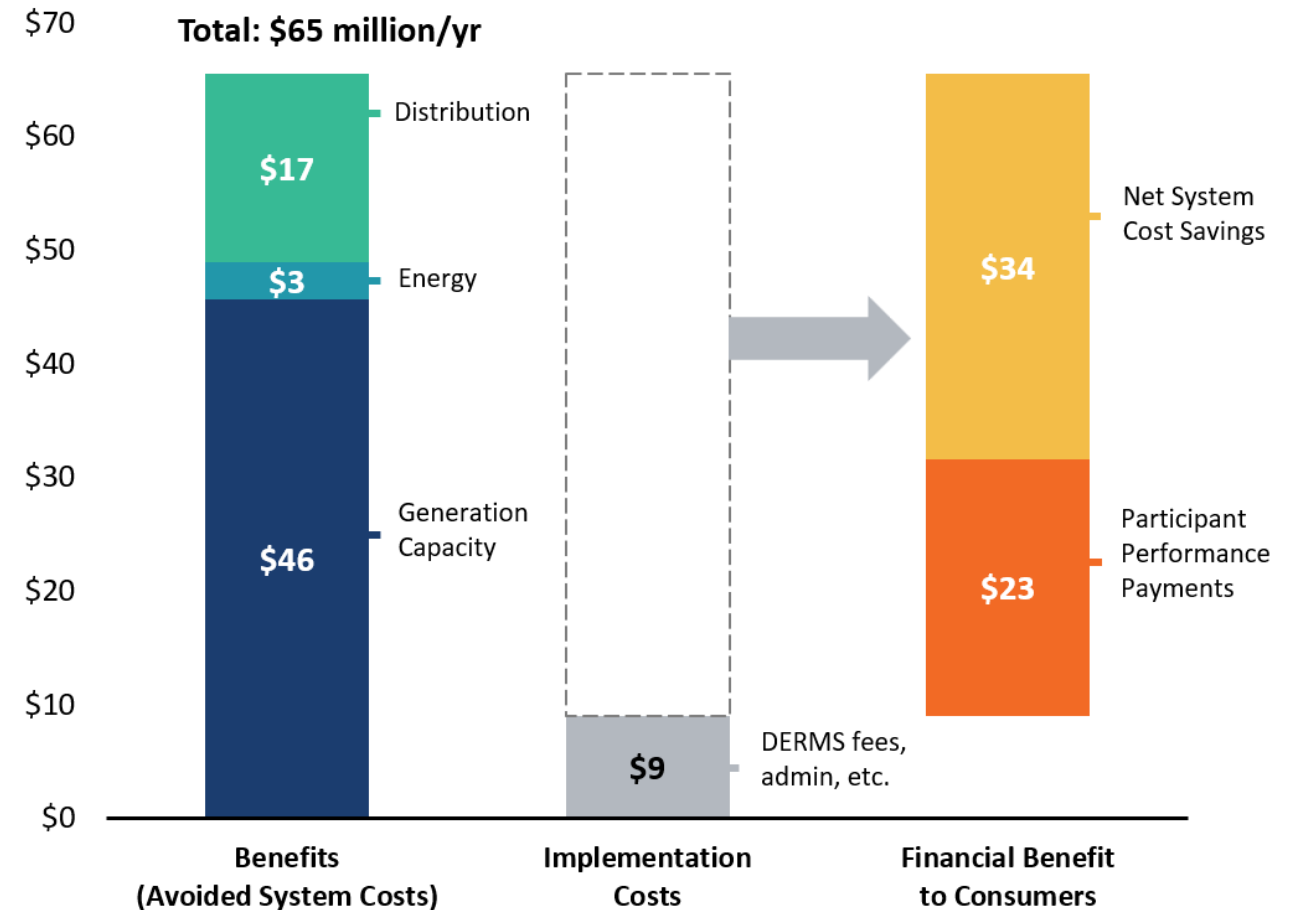
In its first year of operation, the VPP avoids \$65 million per year in capacity, energy, and distribution upgrade costs. To deliver this value requires just \$9 million per year in implementation costs (e.g., marketing and administration costs, and incremental device integration / software fees).

Further, the primary “cost” of the VPP is not really a cost at all, but a performance payment to participating households. At the performance payments assumed in this study, the utility would pay participating VPP households roughly \$23 million per year instead of writing checks to power developers.

The result is that the vast majority of the value created by the VPP goes to consumers, either directly through participant performance payments or indirectly through net system cost savings that are shared across all ratepayers.

Note: Analysis assumes average VPP performance payment of \$75/kW-yr. This value is an average—performance payments vary across different technologies within the VPP. Totals may not sum due to rounding. See Technical Appendix for further detail.

Annual Value of VPP Portfolio (\$2026 million/yr)



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Section IV: **The Affordability Impacts of VPPs**

Entering an Era of Electricity Rate Growth

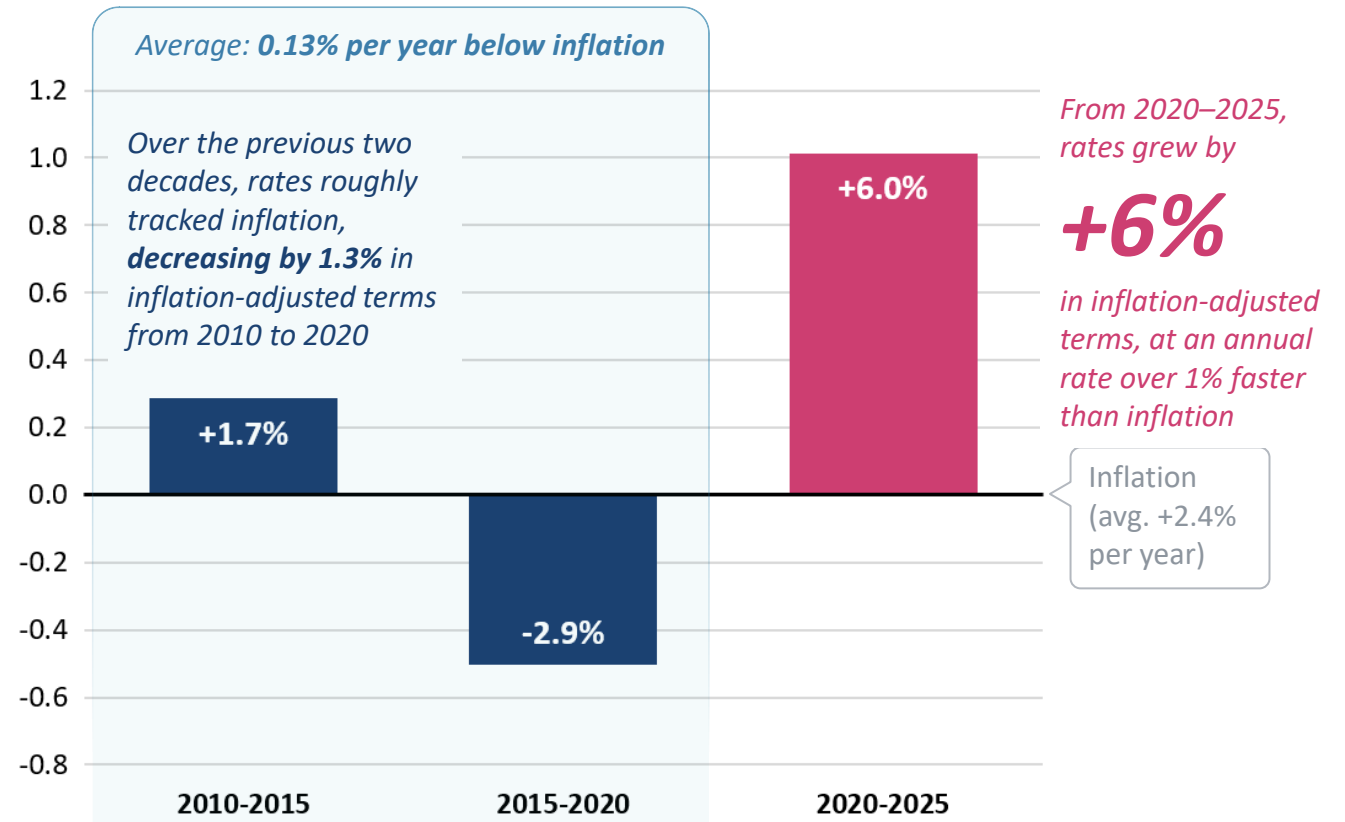
While retail electricity rates have historically tracked inflation, recent rate growth above inflation has exacerbated affordability concerns.

Electricity rates increased in nominal terms over the last few decades, but they tended to increase at the [same rate or slower](#) than other consumer prices. From 2010 to 2020, residential retail rates increased at an average rate just below inflation, ending the decade 1.3% lower in inflation-adjusted (“real”) terms.

However, a confluence of factors—including upgrades to aging infrastructure and increased equipment costs, as well as the effects of recent load growth—have seen electricity rates rise significantly faster than inflation since 2020. From 2020 to 2025, rates increased by 1.2% per year in inflation-adjusted terms—6% total.

This rate growth is expected to continue, with the most recent data showing that rates increased by 1.1% in inflation-adjusted terms over the single year from June 2025 to June 2026.

Change in Inflation-Adjusted Residential Electricity Rates
(2026c/kWh)



Sources & Notes: Historical retail rate data from 2026 EIA-861. Inflation estimates calculated using historical CPI data from the U.S. Bureau of Labor Statistics.

The VPP Cuts Expected Household Electricity Bill Increases in Half

By the time the VPP reaches scale (approximately five years), it reduces bill increases for average households by more than half. Bill increases are almost completely offset for VPP participants in inflation-adjusted terms.

1

Avg. increase in annual bill after 5 years **without** VPP

\$98 (2026 dollars)

Based on recent trends, we consider a forward-looking scenario in which, absent the deployment of a VPP, retail electricity bills continue to grow at a pace that is 1% per year faster than inflation. At this rate of growth over 5 years, average annual household bills will be nearly \$100 greater than today in inflation-adjusted terms.

2

Bill savings with VPP for avg. household

-\$56 (2026 dollars)

The net value of the VPP (avoided resource costs net of performance payments and implementation costs) flows through to residential rates, saving all households money on their electricity bill. Since a significant share of the customer base participates in the VPP, customers see a sizable payment on average.

3

Bill savings with VPP for non-participating households

-\$34 (2026 dollars)

Non-participating households do not receive performance payments, but still avoid a third of the bill increase through net system cost savings that flow through to all ratepayers.

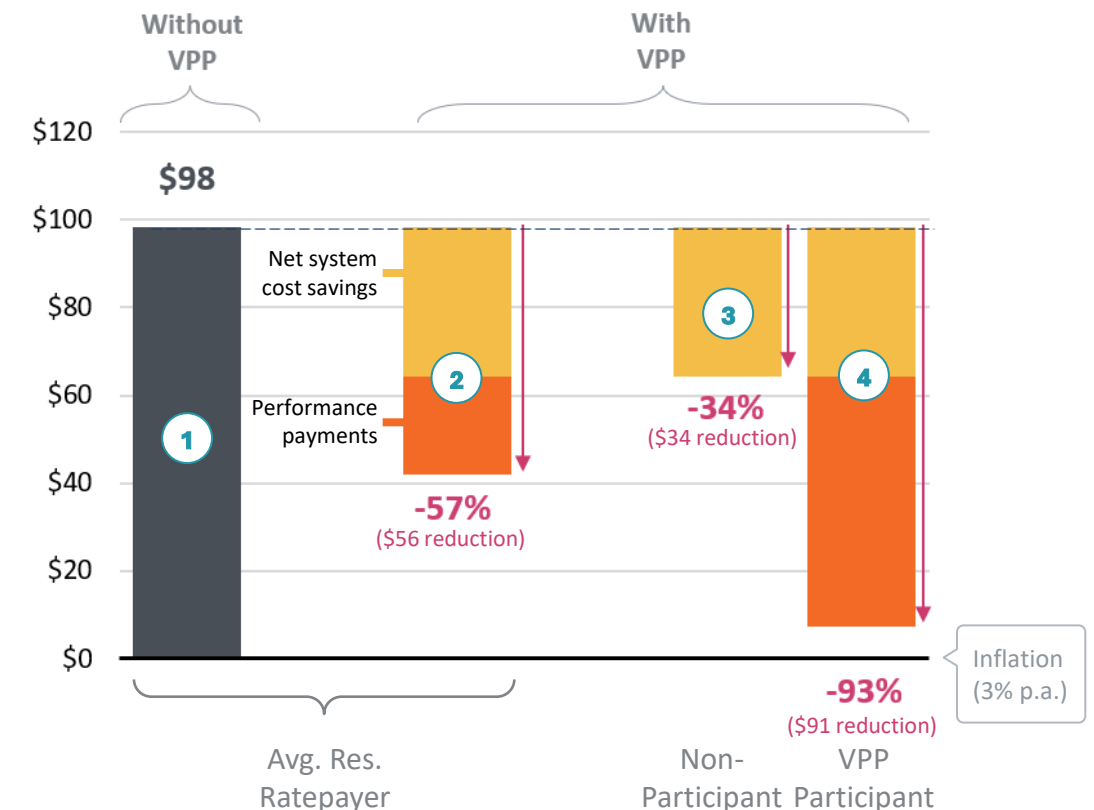
4

Bill savings with VPP for avg. participants

-\$91 (2026 dollars)

With the addition of performance payments, bill growth for participating households is almost entirely offset in inflation-adjusted terms.

Change in Bill After Five Years, Without and With VPP (\$2026/yr)



Note: To maintain this relative level of bill relief in later years, the VPP would need to continue to scale beyond the level modeled in this study.

Conditions Will Vary Across Utility Jurisdictions

We analyzed the robustness of our bill impact results to variations in key input assumptions.

Assumption	Base Case	Upside Case	Constrained Case
DER adoption	Reasonable technology adoption projections based on nationally representative utilities and accounting for current policy environment.	Assumes DER adoption rebounds from recent policy-related headwinds, likely due to remediating policy interventions.	Assumes continued delays in EV, solar and battery adoption and lower-than-anticipated smart thermostat adoption.
VPP enrollment	Assumes full-scale roll-out across all programs and widespread implementation of OEM-led enrollment strategies. More limited experience with OEM-led enrollment for EV managed charging and BTM battery storage moderates anticipated efficacy of these strategies.	Assumes aggressive OEM-led enrollment strategies such as opt-out (default) enrollment (e.g., Sunrun in Puerto Rico).	Assumes OEM-led enrollment strategies are limited in their effectiveness, particularly for EV managed charging and BTM battery storage.
Capacity value	Benchmarked against recent cost increases due to gas turbine supply chain constraints. Marginal cost of generation capacity of \$200/kW-yr (2026 dollars) with capacity accreditation factor of 75%.	Assumes persistence/exacerbation of elevated gas turbine costs resulting in a marginal cost of capacity of \$250/kW-yr (2026 dollars). ² VPP receives 90% capacity accreditation (aligned with value awarded to DR in PJM). Accredited capacity also receives a 15% gross-up to account for avoided reserve margin procurement.	Assumes gas turbine supply chain constraints are largely alleviated by early 2030s, lowering marginal cost of capacity to \$140/kW-yr. VPP only accredited at a more modest accreditation factor of 60%.
Distribution load growth	Assumes 0.8% annual load growth on the distribution system based on a review of MISO's 2026 Long-Term Load Forecast. ¹	Slower load growth reduces the load relief needed to defer capital upgrades. Assumes a growth rate of 0.6% based on MISO LTLF when excluding data center and emerging manufacturing load.	Faster load growth makes it more difficult to deliver the load relief needed to defer distribution upgrades. Assumes a 1% growth rate based on the upper end of the range derived from the MISO LTLF.
Implementation costs	Assumes \$30/kW-yr (2026 dollars) for DERMS fees, admin costs, etc.	Assumes \$25/kW-yr.	Assumes \$40/kW-yr.

1. MISO (2026), 2026 Long-Term Load Forecasting (LTLF) Results Summary

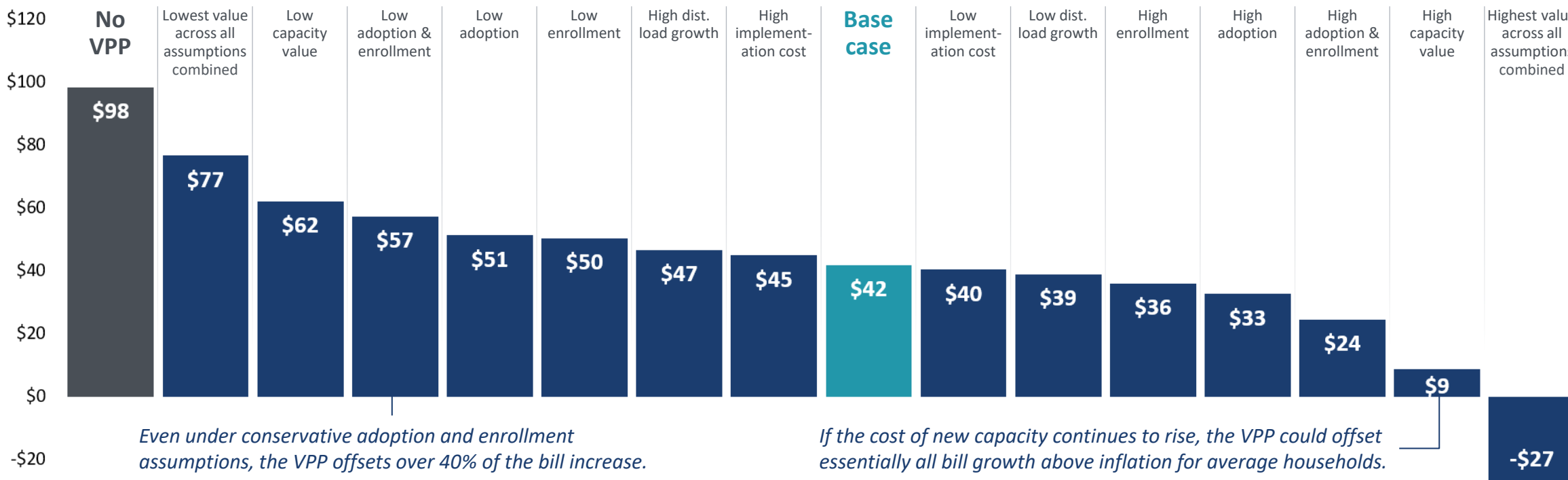
2. This value is consistent with recent upper-bound estimates—for example, recent results from [Ascend Analytics](#) and [E3](#) suggest net CONE values of \$275/kW-yr in 2026 for a gas CC in PJM and \$240/kW-yr for a gas CT in 2030 nationwide, respectively. See Technical Appendix for further benchmarks.

See Volume II: Technical Appendix for specific input assumptions across sensitivity cases

Bill Savings are Robust Across a Range of Future Scenarios

Even when assuming the most extreme downside case tested in this analysis, the VPP avoids nearly a quarter of the projected average household bill increase in year 5. Bill impacts are most sensitive to changes in avoided capacity costs—if high gas turbine costs persist, the VPP could provide enough value to almost completely offset rate growth in inflation-adjusted terms.

Change in Bill After Five Years With VPP, Average Residential Ratepayer (\$2026/yr)



The top half of the image features a solid blue background with a subtle, repeating geometric pattern of triangles and squares in varying shades of blue.

Section V: **Reaching Scale**

Achieving “Utility-Scale” VPPs

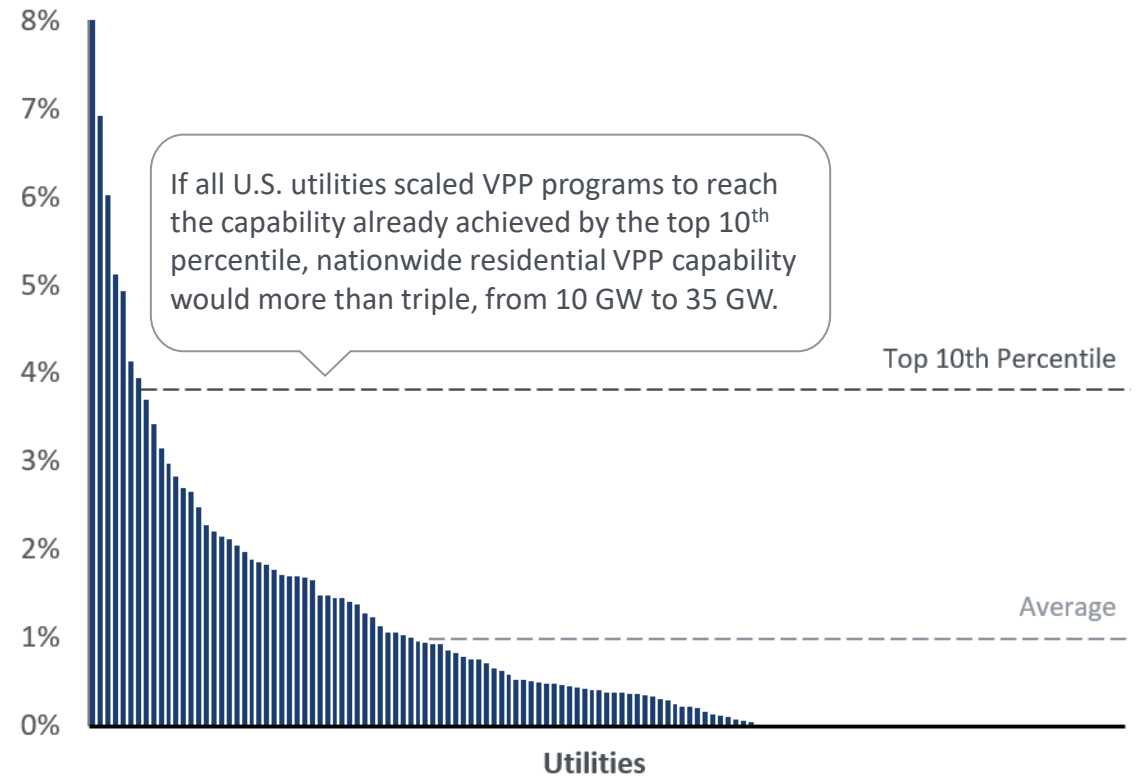
If all utilities were to achieve a 4% system peak reduction from residential VPPs, national VPP capability would more than triple, from 10 GW to 35 GW.

For the affordability benefits of VPPs to materialize at the level described in this study, VPPs will need to scale quickly and significantly. National data support the achievability of this outcome.

Across U.S. utilities, residential DR capability currently represents 1.1% of system peak demand on average. By comparison, the 4% system peak impact modeled in our analysis equates roughly to the top 10th percentile of utilities. **If all utilities were to achieve a 4% system peak reduction, the national capability would more than triple, from 10 GW to 35 GW.** While many factors will drive differences in the achievable level of residential VPP capability across utilities, this demonstrates significant room for growth on a national scale.

Further, during the five-year period between 2006 and 2011, national demand response capability doubled from 30 GW to 60 GW. This was driven primarily by FERC policy opening wholesale markets to DR participation. If new initiatives were to unlock another 30 GW of capacity over the *next* five years, it would offset up to half of forecasted national peak demand growth over that period. Demand flexibility has been “built” quickly in the past, and can be again.

U.S. Utility Residential DR Capability, as % of System Peak Demand



Notes: Based on EIA-861 data. Capability is 2022-2024 average. For simplicity, results are shown for utilities with at least 1,000 MW of peak demand. Y-axis values stop at 8% but one utility in the dataset reports 16% capability. Averages and percentiles are load-weighted.

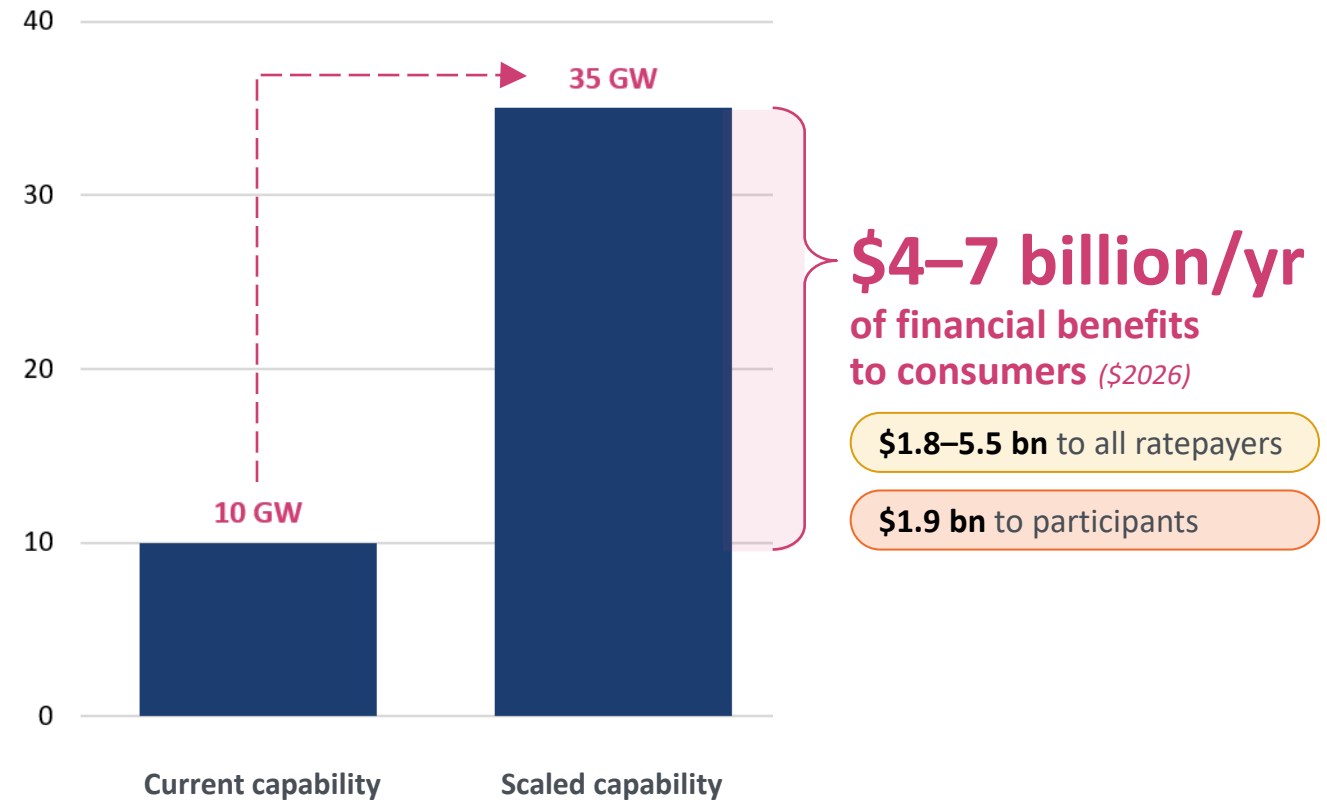
Unlocking \$4–7 billion per year through enrollment, not deployment

The addition of 25 GW of national residential VPP capacity outlined on the previous page would generate an extra \$4–7 billion per year in financial benefits to households and could be reached primarily by enrolling and activating existing DERs.

Tapping into latent DR potential through improved enrollment presents an efficient pathway to achieving 35 GW of residential VPP capacity nationwide and could yield significant financial benefits to consumers. Extrapolating the modeling in this study nationally, an extra 25 GW of DR capability could generate **\$4–7 billion of annual value** to consumers, with half to three quarters of that going to all ratepayers and the remainder additionally being paid directly to participants.

Bringing VPPs to scale by focusing on activating existing assets offers an opportunity to generate these savings in the near term while consumer bill pressure is elevated, without needing to wait for or incentivize a new generation of devices to be deployed. The next two pages provide examples of OEM-led enrollment strategies that have been successful in scaling VPPs.

U.S. Utility Residential Demand Flexibility and Value (GW)



Notes: Financial benefits calculated by applying the low and high estimates of levelized VPP value across sensitivity cases (see slide 24).

Case Study in OEM-Led Enrollment: Energy Shift

Through frictionless activation and comfort-first operation, Everyday Electric has found that roughly four times as many customers activate a suite of energy management automations, including VPP, compared to traditional and more narrow DR built around more noticeable shifts. The reduction in magnitude of shift is far outweighed by the increase in scale, creating a larger resource.

Energy Shift Features

Frictionless activation: When participating smart thermostat customers set up their device or mobile app, they can activate “Energy Shift” with a very simple setup flow. The feature has seen significant adoption, creating an aggregate grid resource that can deliver significant load reductions during periods of grid stress.

Personalized adjustments: Shifts are tailored to user preferences and typically involve smaller, shorter set-point changes that run more often than traditional DR, maintaining comfort and reducing frustration. Once activated by the relevant system operator, Energy Shift customers can become eligible for performance-based incentives.

Event experience: Customers can see an Energy Shift happening on their thermostat and in the mobile app and can review activity in monthly recap emails. During shifts, customers can adjust their temperature or opt out at any time, and can also turn off Energy Shift in their thermostat settings.

ESC enrollment compared to traditional DR enrollment

~4x

Through its streamlined enrollment process, Everyday Electric has found nearly four times as many customers activate the Energy Shift compared to enrollment in traditional DR.

Total resource size compared to traditional DR

~2.5x

Although temperature shifts are smaller, the total resource built from this more customer-focused capability grows to be much larger than traditional demand response.

Customer overrides during events

<4%

Despite always having the option, only a fraction of customers choose to override temperature offsets during Energy Shifts that support local utility and community needs.

Case Study in OEM-Led Enrollment: Battery Auto-Enrollment in Puerto Rico

Sunrun and Tesla scaled participation in Puerto Rico’s Customer Battery Energy Sharing (CBES) program sevenfold in just over a year by auto-enrolling new third-party owned batteries.

CBES Features

CBES is an emergency VPP that leverages distributed battery storage systems and has prevented outages on several occasions.¹

Both new and existing third-party owned (TPO) storage systems are automatically enrolled in CBES unless customers opt out, which they can do at any time. Very few customers opt out of the program. Due to the high value of household resilience in Puerto Rico, aggregators enroll 30% of the battery’s installed capacity.²

Third-party owner (TPO) financing is common in Puerto Rico and already builds in the contractual terms to allow for auto-enrollment.

70–80% of the residential solar market in Puerto Rico is TPO, with nearly 100% storage attachment rates.³

Dec 2024
participants (opt-in)
12,000



May 2026
participants (auto)
82,500

Auto-enrolled CBES
participants in 2026
81%

Switching to auto-enrollment allowed aggregators to scale VPP capacity virtually overnight. Latest data reports that over 80% of CBES participants were auto-enrolled in the program.

Enrollment rate of new Sunrun customers
93%

Attrition rate
<2%

When initially notified of their auto-enrollment in the VPP, only 7% of customers opt out. Once enrolled, almost all customers remain in the program, with only <2% of customers retroactively unenrolling from the VPP.

1. Lutz (2025), [Booming solar and storage are propping up Puerto Rico’s grid this summer](#), in Utility Dive.

2. Puerto Rico Energy Bureau (2026), [Resolution and Order for Joint Motion for Authorization to Increase the Default Enrolled Battery Capacity for Auto-enrolled Customers in the CBES Program](#), Case No. NEPR-MI-2026-0002.

3. Driscoll (2025), [In Puerto Rico, residential solar and storage growth outpaces utility-scale developments](#), in PV Magazine.

Three Pathways to Enabling OEM-Led Enrollment

Today, many customers who would otherwise provide valuable capacity are unable to enroll in or be compensated for demand response programs due to restrictive tariff language. Three simple paths forward could unlock this capacity.

Create New Tariffs

Design new tariffs that **intentionally build in** the ability for OEMs or aggregators to enroll customers without requiring the customer to interface with the utility.

Example: ComEd's BYO Device Load Reduction ([BYODLR](#)) program was designed with stakeholders to **explicitly allow for enrollment by aggregators and OEMs**.

Modify Tariffs

Some existing tariffs or programs contain contractual language that requires customers to re-sign terms and conditions in order to participate in the VPP offering, introducing friction that limits enrollment. **Amending this language** to remove this requirement is a simple change that can increase enrollment.

Clarify Existing Tariffs

In other cases, language may be ambiguous as to whether OEM-led enrollment is permissible. Joint efforts between utilities and stakeholders should **clarify the extent to which OEM-led enrollment is possible under current terms**.

Maintaining clear, informed consent from participants while moving away from onerous enrollment processes

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Section VI: **Conclusion**

Conclusion

This study evaluated the near-term affordability impacts of residential VPPs and their ability to reach scale through OEM-led enrollment.

Planning-grade, utility-scale capacity within five years

Over the next five years, the illustrative VPP scales to over 300 MW through OEM-led enrollment strategies—equivalent to 4% of the utility's coincident system peak and 9% of residential system peak. We demonstrate the value of this installed capacity as a dependable resource through simulations across ten years of hourly data.

Significant financial benefits to consumers

Driven by avoided generation capacity and deferred distribution system costs, the VPP avoids **\$65 million per year** (2026 dollars) in resource costs in its first year of full-scale operation. Of this, **\$56 million per year** is returned to consumers, either directly through participant performance payments or indirectly through net system cost savings shared across all ratepayers.

By the time the VPP reaches scale—in roughly five years—it offsets over half of the expected bill increase

Without the VPP, after five years the average household would pay \$98 more for electricity per year (in real terms) than they did in 2026. The VPP offsets over half of this bill increase for the average residential customer. Non-participants see their bill increase reduced by a third, and bills for participants nearly return to 2026 levels in inflation-adjusted terms.

OEM-led enrollment enables VPPs to reach scale

The VPP in this study scales by tapping into latent residential DR capacity through enhanced enrollment. If utilities across the country were to do the same, national DR capability could scale from 10 GW today to 35 GW, generating an additional **\$4–7 billion per year** (2026 dollars) of financial benefits for consumers.

Driving VPP Affordability Benefits

Targeted efforts in several areas could enable VPPs to more broadly capture the affordability opportunity identified by this study and enable bill savings for residential customers.

System-specific analysis. Our analysis provides an estimate of the significant affordability opportunity provided by VPPs based on a representative U.S. utility system. It is not a substitute for system-specific analysis for states/utilities that are developing new initiatives in this area.

New regulatory models. Many utilities do not have a direct financial incentive to develop residential VPPs rather than investing in conventional infrastructure. New regulatory models could help align utility incentives with the affordability opportunity VPPs provide.

Targeted enrollment and enhanced utility operational capabilities.

Achieving the modeled distribution benefits requires incentives that direct VPP enrollment toward constrained areas of the grid, and for utilities to have the visibility and capability to operate them with grid awareness.

Consideration in planning and market design. To be able to generate cost savings by avoiding investments in generation capacity, VPPs will need to be considered equally with other resource types in utility resource planning processes. Similarly, barriers to VPP participation and accreditation in regional capacity markets may need to be addressed for benefits to be fully realized in restructured states.

Complementary rate design. Residential electricity rates should complement VPP programs. This study accounts for the interaction between VPP dispatch and load-shifting in response to TOU rates—reform to these rate structures should consider this interplay. Similarly, net metering structures can drive or hinder DER adoption and VPP enrollment depending on the magnitude of the incentive and the degree to which customers are exposed to time-varying price signals.

Innovative approaches to customer engagement and enrollment.

Achieving the assumed scale within the five-year study horizon requires widespread improvements—in this analysis, we have specifically assumed OEM-led enrollment drives VPP participation. Modernizing tariffs to facilitate these enrollment strategies is key to realizing the scale assumed in this study.

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