

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

VOLUME II: TECHNICAL APPENDIX

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# Disclaimer

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# I. Introduction

This study analyzed the near-term affordability impacts of residential virtual power plants (VPPs) when harnessed to their full achievable potential. Specifically, we evaluated the scale that a residential VPP could achieve through innovative approaches to customer enrollment in an illustrative, nationally representative utility, and determined the value this VPP could generate to estimate affordability benefits for households. We describe the findings of the study in our Volume I Summary Report. Highlights of the findings are summarized below:

- Over the next five years, the illustrative VPP scales to over 300 MW through original equipment manufacturer (OEM)-led enrollment strategies, equivalent to 4% of the utility's coincident system peak.
- The VPP generates \$65 million per year (2026 dollars) in value in its first year online, the vast majority of which is returned to customers through net system cost savings or participant performance payments.
- By the time the VPP reaches scale, it offsets over half of the expected bill increase for the average household, and almost completely offsets the bill increase for households participating in the VPP.
- If latent residential demand response (DR) capacity was unlocked through enhanced enrollment, 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.

This Volume II Technical Appendix provides further detail on the assumptions, data sources, and calculations used in our analysis.

The analysis focuses on three residential distributed energy resources (DERs): smart thermostats, electric vehicle (EV) managed charging, and behind-the-meter (BTM) battery storage. We first estimate the number of customers likely to own each technology and the share that could enroll in a VPP in the next five years. We then estimate the dependable capacity, energy, and distribution-system value associated with the resulting portfolio. Finally, we translate this value into affordability impacts for residential customers.

## II. The Representative Utility System

To evaluate the affordability benefits of VPPs, we defined a representative utility as the basis for our analysis. The illustrative utility is based on nationally representative characteristics to ensure results are nationally relevant. Where regional assumptions or data were needed, we used the characteristics of Midwestern utilities/markets. Table 1 provides a summary of the key assumptions around the representative utility system.

TABLE 1: OVERVIEW OF REPRESENTATIVE UTILITY

| Variable                                                     | Value        | Source/Notes                                                       |
|--------------------------------------------------------------|--------------|--------------------------------------------------------------------|
| Residential customer count                                   | 1,000,000    |                                                                    |
| Average peak coincident demand per customer (kW)             | 3.5          |                                                                    |
| Average annual electricity consumption per customer (kWh/yr) | 10,000       | EIA RECS (2020), <a href="#">Table CE2.1</a> . Nationwide average. |
| Residential peak coincident demand                           | 3,500        |                                                                    |
| C&I customer coincident peak demand                          | 3,500        |                                                                    |
| <b>Total coincident peak summer demand</b>                   | <b>7,000</b> |                                                                    |

We benchmarked the size of the illustrative utility against the largest investor-owned utilities in Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana, and Missouri using 2024 EIA Form 861 data. Across those states, the largest investor-owned utilities average approximately 1.4 million residential customers, 9.3 GW of summer peak demand, and 7.0 GW of winter peak demand. Table 2 shows the summary of this benchmarking.

TABLE 2: SUMMARY STATISTICS FOR LARGEST IOU IN A SAMPLE OF MIDWESTERN STATES

| State          | Residential customer count (2024) | 2024 summer peak (MW) | 2024 winter peak (MW) |
|----------------|-----------------------------------|-----------------------|-----------------------|
| MN             | 1,230,057                         | 7,444                 | 5,216                 |
| WI             | 1,048,148                         | 5,373                 | 3,658                 |
| MI             | 2,067,758                         | 10,689                | 6,803                 |
| IA             | 632,436                           | 5,623                 | 4,675                 |
| IL             | 2,922,223                         | 21,560                | 15,077                |
| IN             | 796,265                           | 5,840                 | 6,487                 |
| MO             | 1,095,619                         | 8,350                 | 6,917                 |
| <b>Average</b> | <b>1,398,929</b>                  | <b>9,268</b>          | <b>6,976</b>          |

### III. Developing the Illustrative VPP

To calculate the total installed capacity of the illustrative VPP, we first determined the number of participants for each program type, then multiplied by the expected load reduction per participant to obtain the total installed capacity of the VPP in megawatts. Table 3 summarizes the composition of the illustrative VPP. The subsequent sections detail the bases and assumptions used in this calculation for each technology type.

It should be noted that we assume a portion of VPP participants are enrolled in time-of-use (TOU) rates, and throughout this section we estimate the number of TOU versus non-TOU participants for EV managed charging and BTM battery storage.<sup>1</sup> This distinction becomes important in Section IV, where the value that each resource can provide is dependent on whether the participant is already enrolled in a TOU rate. For the purposes of this section, we express the installed capacity of the VPP in terms of the average load reduction that a given resource could be expected to provide, regardless of whether this load reduction is incremental to baseline load-shifting behavior (i.e., as if all customers were not on TOU rates). We then apply derates or adders for TOU participants when estimating the value generated by the VPP, as described in Section IV.

TABLE 3: COMPOSITION OF THE ILLUSTRATIVE VPP

| Program                                 | Participants     | Per-Participant Load Reduction (kW per event) | Installed Capacity (MW) |
|-----------------------------------------|------------------|-----------------------------------------------|-------------------------|
| Smart thermostats (ESC)                 | 302,839          | 0.58                                          | 176                     |
| Smart thermostats (high-impact)         | 66,481           | 0.90                                          | 60                      |
| EV managed charging                     | 64,680           | 0.68                                          | 44                      |
| BTM battery storage (organic adopters)* | 3,388            | 3.6                                           | 12                      |
| BTM battery storage (VPP adopters)*     | 1,291            | 7.2                                           | 9                       |
| <b>Total VPP</b>                        | <b>394,811**</b> | —                                             | <b>301</b>              |

*Notes:* Per-participant load reductions are used to estimate the total installed capacity of the VPP. It should be noted that these values are not necessarily equal or proportional to the load reduction that each participant can receive accreditation for when determining the capacity value of the VPP. EV managed charging and BTM battery storage customers on TOU rates receive less capacity accreditation than non-TOU customers, since they likely already shift their load—see Section IV.A.

\*“Organic adopters” refers to customers who are projected to attach storage to rooftop solar installations, regardless of the VPP offering. “VPP adopters” are customers incentivized to adopt batteries by the VPP offering.

\*\*We assume that 10% of participants participate via more than one DER. Therefore, the value shown here is 90% of the sum of the “Participants” column.

<sup>1</sup> We do not make this distinction for smart thermostats, as we assume that customers do not shift their HVAC load according to TOU rate price signals.

## A. Technology Adoption & VPP Enrollment

Table 4 summarizes the adoption and VPP enrollment rates of each of the technology types in the VPP; the subsequent sections lay out the bases and assumptions underpinning these rates.

TABLE 4: SUMMARY OF 2032 TECHNOLOGY ADOPTION & ENROLLMENT RATES

| Program                    | 2032 Adoption Rate<br>(% of res. customers) | VPP Enrollment Rate<br>(% of eligible customers) |
|----------------------------|---------------------------------------------|--------------------------------------------------|
| <b>Smart thermostats</b>   | <b>44%</b>                                  | <b>83%</b>                                       |
| ESC                        | —                                           | 68%                                              |
| High-impact                | —                                           | 15%                                              |
| <b>EV managed charging</b> | <b>22%</b>                                  | <b>30%</b>                                       |
| Non-TOU                    | —                                           | 15%                                              |
| TOU                        | —                                           | 15%                                              |
| <b>BTM battery storage</b> | <b>0.94%</b>                                | <b>50%</b>                                       |
| Organic adopters           | 0.81%                                       | 42%                                              |
| VPP adopters               | 0.13%                                       | 100%                                             |

*Notes:* Electric vehicle adoption is estimated as the share of the light-duty vehicle stock that is electric multiplied by the average number of vehicles per household in the Midwest (1.96) according to the U.S. DOT National Household Transport Survey.<sup>2</sup> Smart thermostat and EV managed charging enrollment rates are expressed as a share of total technology adoption (adoption of smart thermostats and adoption of EVs, respectively). BTM battery storage enrollment rates are expressed as a percentage of the adoption in each adoption “category”—i.e., 50% of total battery owners, which comprises 42% of owners who adopted batteries alongside rooftop solar (“organic adopters”) and 100% of customers who adopted batteries specifically to participate in the VPP (“VPP adopters”).

### Smart Thermostats

Smart thermostat adoption and VPP enrollment rates were informed by a combination of public data and internal data from Everyday Electric; the approach to estimating both is summarized in Figure 1. To estimate smart thermostat adoption by 2032, we first estimated the share of U.S. households with central AC in 2020 using data from the EIA Residential Energy Consumption Survey (RECS),<sup>3</sup> as well as the share of those customers with smart thermostats. We accounted for adoption between 2020 and 2026 using an assumed annual adoption rate of 4.3 million devices per year based on EPA Energy Star shipments data from 2020 to 2024,<sup>4</sup> an annual churn rate of 5%, and an assumed residential customer annual growth rate of 1.19% based on historical EIA-861 residential customer counts from 2019 to 2024. This gave us a 2026 smart thermostat adoption rate of 36% of central AC customers; we grossed this up to 40% to

<sup>2</sup> U.S. DOT (2024), [2022 National Household Transport Survey](#), Table 2-7, p 14.

<sup>3</sup> U.S. EIA (2023), [2020 Residential Energy Consumption Survey](#), Table HC7.7.

<sup>4</sup> U.S. EPA (2024), [ENERGY STAR Unit Shipments Data](#).

represent a relatively progressive investor-owned utility. With input from Everyday Electric, we then assumed an additional 20% of central AC customers would adopt smart thermostats between 2026 and 2032.

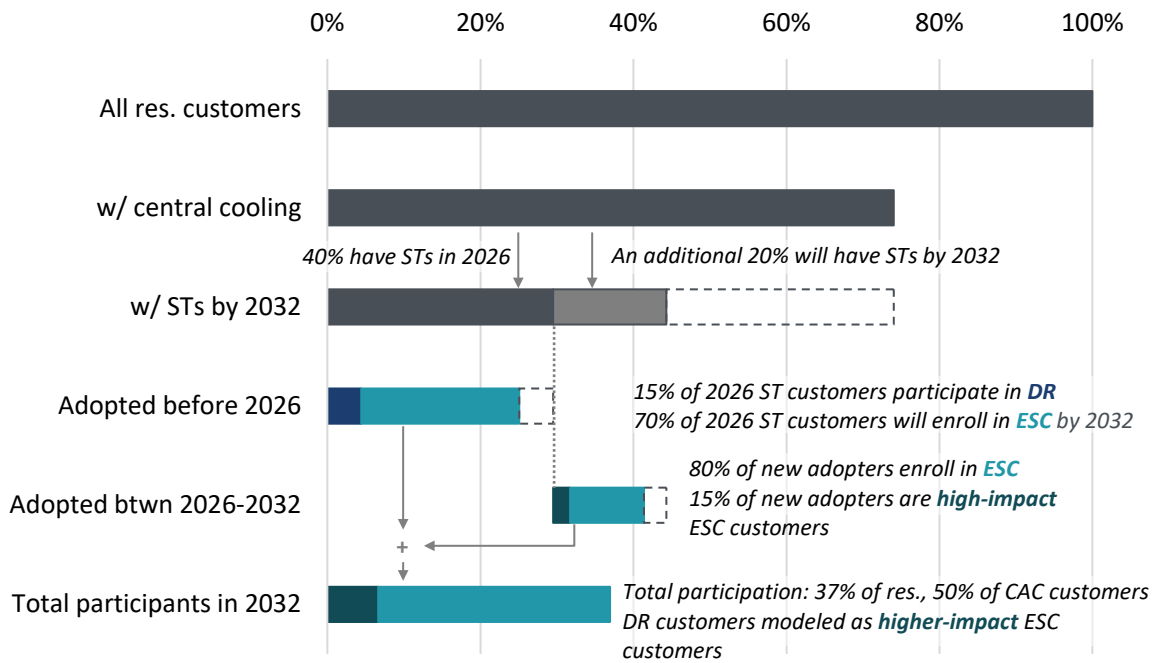
VPP enrollment assumptions were informed by Everyday Electric’s existing experience with its “Energy Shift Capacity” (ESC) offering for Nest<sup>5</sup> thermostats, which has scaled smart thermostat enrollment by a factor of four through frictionless enrollment and comfort-first operation.<sup>6</sup> We assumed that 80% of customers that adopt smart thermostats between 2026 and 2032 will enroll in ESC, and that 70% of the customers who already have smart thermostats in 2026 will have enrolled by 2032. In addition, we assume 15% of new and existing customers will enroll as “high-impact” ESC participants, based on enrollment rates in traditional DR programs; we assume these customers are more price responsive and are therefore able to provide load reductions similar to that of traditional DR (see Section III.B). This results in a total of 83% of smart thermostat customers participating in the VPP—68% as lower-impact ESC customers, and 15% as “high-impact” ESC customers.

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<sup>5</sup> Google, Google Home, Nest, Nest Renew, Nest Thermostat, Nest Learning Thermostat, Rush Hour Rewards, and the Google and Nest logos are trademarks of Google LLC.

<sup>6</sup> Renew Home (2026), [Energy Shift Capacity: 4GW of New Flexible Capacity Ready to be Rewarded Now](#), Press Release.

FIGURE 1: SMART THERMOSTAT ADOPTION AND ENROLLMENT

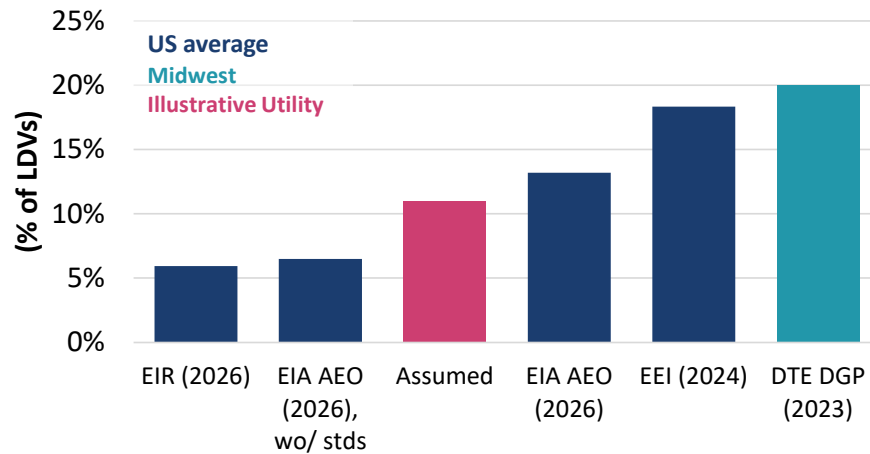


## EV Managed Charging

We assume 11% of the light-duty vehicle (LDV) stock is electric by 2032. At a Midwest-average car ownership rate of 1.96 LDVs per household, this corresponds to 22% of residential customers owning an EV.

Figure 2 shows how our assumed EV adoption trajectory lines up with several different benchmarks. We reviewed historical and projected EV adoption trends in seven Midwestern states (Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana and Missouri), as well as several national and utility-specific benchmarks. The passage of the One Big Beautiful Bill Act (OBBBA) in 2025 represented a headwind for EV adoption that was not anticipated by earlier studies; forecasts from the EIA 2026 Annual Energy Outlook (AEO) and Enverus Intelligence Research that account for these headwinds were therefore included. The assumed 2032 adoption rate of 11% is below the U.S. average projected by the EIA 2026 AEO (13%) to distinguish from strong/outlier EV markets (e.g., CA), and significantly lower than pre-OBBBA forecasts. An upside case where EV adoption recovers from OBBBA setbacks is evaluated in the sensitivity analysis.

FIGURE 2: PROJECTED 2032 ELECTRIC SHARE OF LIGHT-DUTY VEHICLE (LDV) STOCK



*Sources and Notes:* EIA data from the 2026 [Annual Energy Outlook](#) (AEO); "wo/ stds" refers to a case with repealed EPA tailpipe emissions standards. EEI data from 2024 EV Sales and Charging Infrastructure Forecast [study](#). Estimates for DTE Energy come from the 2023 DTE [Distribution Grid Plan](#). Enverus Intelligence Research (EIR) data from June 2026 EIR [EV Adoption Forecast](#). Assumed adoption trajectory follows the average growth rate across sampled Midwestern states from 2020 to 2026, then switches to a slower growth rate than assumed in the NREL study to reflect market headwinds observed since that study's publication.

When estimating enrollment of EVs in an EV managed charging program, we distinguish between EV owners on time-of-use (TOU) or other time-varying rates and those on conventional flat volumetric rates. EV owners on TOU rates likely already shift their charging load—this means that incremental capacity and energy value of VPP enrollment is low for these customers. However, these customers may exacerbate distribution system constraints through charging “snapback”, so enrolling them in VPPs increases distribution value. See further discussion of the differences between value created by TOU and non-TOU participants in Section IV.

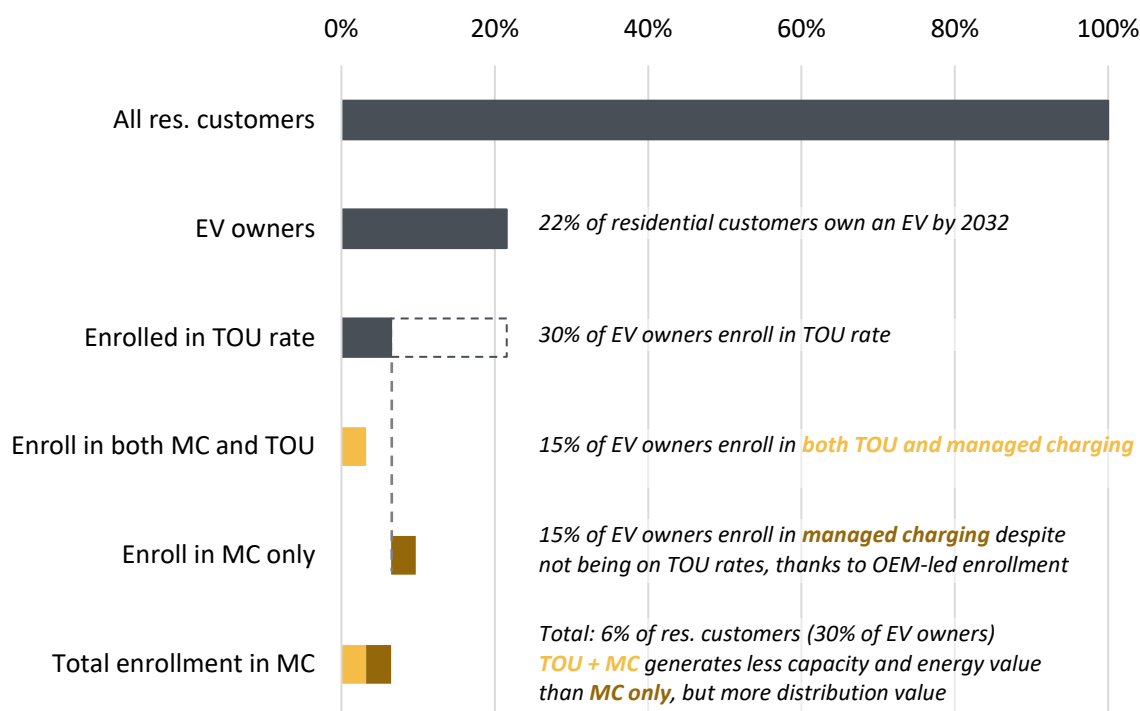
We assume that 30% of EV owners enroll in TOU rates based on shares reported in Plug In America’s 2025 EV Driver Survey<sup>7</sup> (23%) and the Smart Electric Power Alliance’s (SEPA) 2019 EV rates report<sup>8</sup> (22%) and assuming increased enrollment by 2032. Since these customers have implicitly indicated a tolerance to shift their charging load, we assume 50% of TOU-enrolled EV owners enroll in the managed charging program (i.e., 15% of all EV owners). We then assume that 21% of non-TOU EV owners enroll in the managed charging program through OEM-led enrollment strategies (i.e., 15% of all EV owners). This results in a total enrollment rate of 30% of EV owners, or 6% of residential customers.

<sup>7</sup> Plug In America (2025), [EV Driver Survey](#), p. 17.

<sup>8</sup> Smart Electric Power Alliance (2019), [Residential Electric Vehicle Rates That Work: Attributes That Increase Enrollment](#), p. 21. Estimated using 46% of non-Californian EV owners reporting having access to a TOU rate and 48% of these customers enrolling in the TOU rate.

This enrollment rate is on par with enrollment rates in prominent passive managed charging programs such as New York’s SmartCharge NY program.<sup>9</sup> Active managed charging programs are comparatively nascent, and participation is more limited, typically ranging from 7–10% for prominent programs.<sup>10</sup> However, participation in active managed charging is expected to increase as these programs reach scale, and OEM-led enrollment strategies have the capacity to further boost this enrollment.

FIGURE 3: ASSUMED EV MANAGED CHARGING VPP ENROLLMENT



## BTM Battery Storage

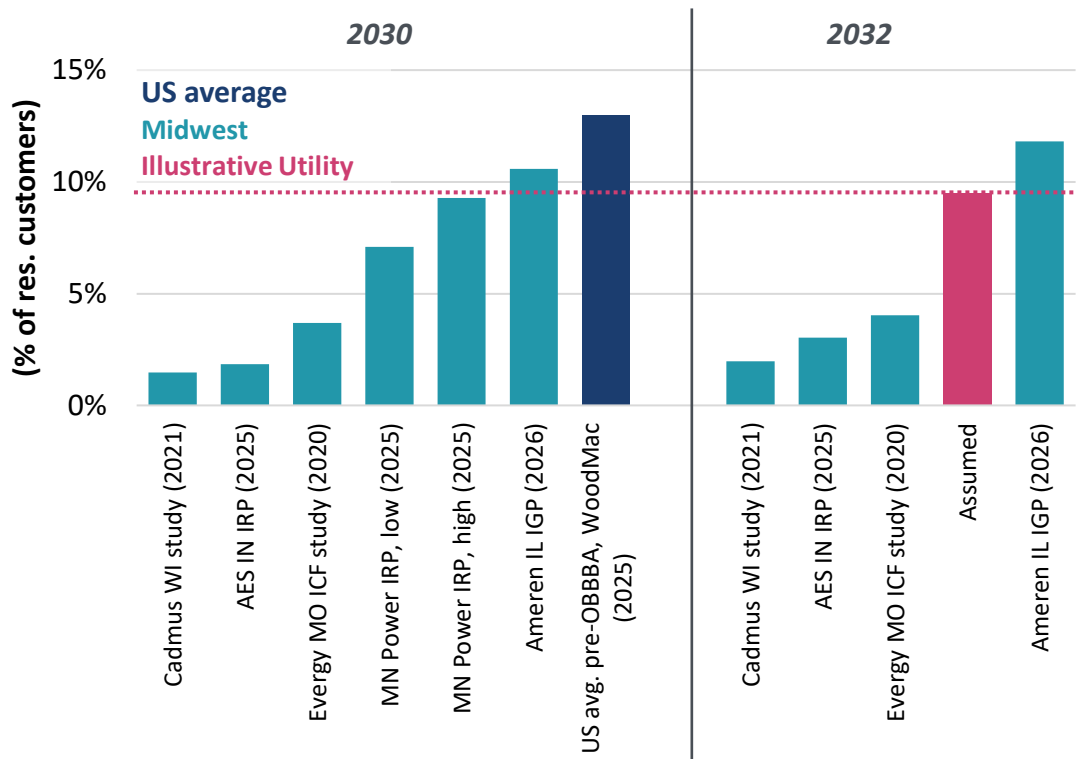
We estimated residential BTM battery storage adoption by considering (a) “organic adopters”, who we assume attach battery storage to their rooftop solar installations; and (b) “VPP adopters”, who we assume install battery storage (either attached to solar or as a standalone resource) in order to participate in the VPP program.

<sup>9</sup> ConEdison reported 25.9% enrollment in SmartCharge NY amongst residential EV owners at the end of 2024. ConEdison (2025), [Distributed System Implementation Plan](#), p. 88.

<sup>10</sup> Benchmarks include DTE Electric’s Smart Charge Program with approx. 7.3% enrollment (DTE Electric [Transportation Electrification Plan](#), 2026, pp. 8 and 64), Puget Sound Energy’s Flex EV program with approx. 7% (PSE [RFP for DSM](#), 2025, p. 41), and BGE’s target for its Smart Charge Management program of approx. 10% by the end of 2027 (MD PSC [Electric System Planning](#), 2025, p. 14).

To estimate organic battery adoption, we projected residential solar adoption and storage attachment rates to new solar installations over the next five years. Figure 4 shows our assumed rooftop solar adoption trajectory in comparison to other benchmarks. We assume rooftop solar penetration reaches 9.5% of residential households by 2032—this is below recent five-year projections from strong Midwestern solar markets (e.g., 12% in IL) to account for OBBBA-related headwinds. An upside case where solar adoption recovers from OBBBA setbacks is evaluated in the sensitivity analysis.

FIGURE 4: COMPARISON OF ASSUMED RESIDENTIAL SOLAR ADOPTION AGAINST 2030 AND 2032 BENCHMARKS

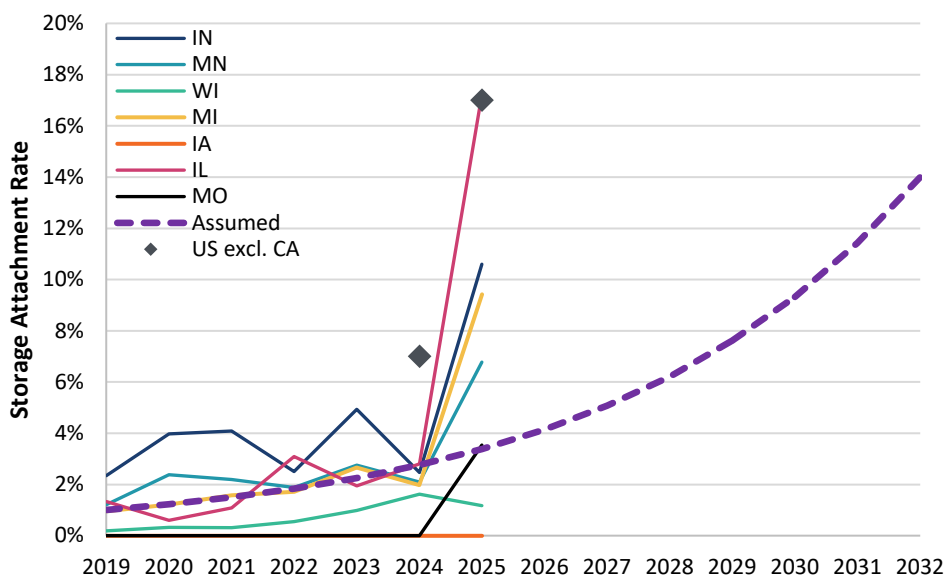


*Sources and Notes:* Assumed adoption trajectory based on average 2026 adoption rate across sampled Midwestern states of 2% and compound annual growth rate (CAGR) of 30% (historical average across sampled Midwestern states) out to 2030, then linear growth from 2030 to 2032. 2030 and 2032 adoption estimates come from the following sources: AES Indiana’s 2025 [IRP](#); Minnesota Power’s 2025 distributed solar [RFP](#); Cadmus’ 2021 Solar Potential [Study](#) for the WI PSC; Ameren IL’s 2026 [Integrated Grid Plan](#); ICF’s 2020 BTM Solar & Storage Forecast [Study](#) for Energys; and WoodMackenzie’s 2025 solar adoption [forecast](#) for the U.S. average results.

Figure 5 shows our assumed storage attachment rate to new solar installations compared to historical attachments in key states. 2025 saw significant increases in storage attachment rates—excluding California, the nationwide average jumped from 7% to 17% from 2024 to 2025. However, attachment rates vary significantly by state, and nationwide averages are heavily skewed by more established residential battery markets (e.g., Illinois). We assume

attachment rates grow steadily up to 14% of new solar installations in 2032 in the face of electricity rate pressure, but remain below the 2025 U.S.-minus-CA average. We also assume no net-metering tariff reform (which typically drives sharp increases in attachment rates, as observed in California and Illinois).

FIGURE 5: PROJECTED STORAGE ATTACHMENT RATE



*Sources and Notes:* Historical storage attachment rates from LBNL "[Tracking the Sun](#)" dataset (2026). Assumed projection based on an assumed attachment rate CAGR of 20% in the absence of net energy metering policy reform—such reform would likely increase storage attachment rates, as observed in CA and IL.

By modeling stock turnover from 2024 to 2032, we estimate that 0.81% of residential customers will have organically adopted a BTM battery by 2032. To estimate adoption amongst “VPP adopters”, we assume that the opportunity to enroll in the VPP drives 16% incremental adoption—i.e., an additional 0.13%, to bring total BTM battery adoption to 0.94% by 2032. This assumption was based on recent Tesla Energy statistical analysis of battery VPP program participation, which found that 16% more customers would adopt BTM storage at incentive levels equal to those offered under California’s Demand Side Grid Support (DSGS) program.<sup>11</sup>

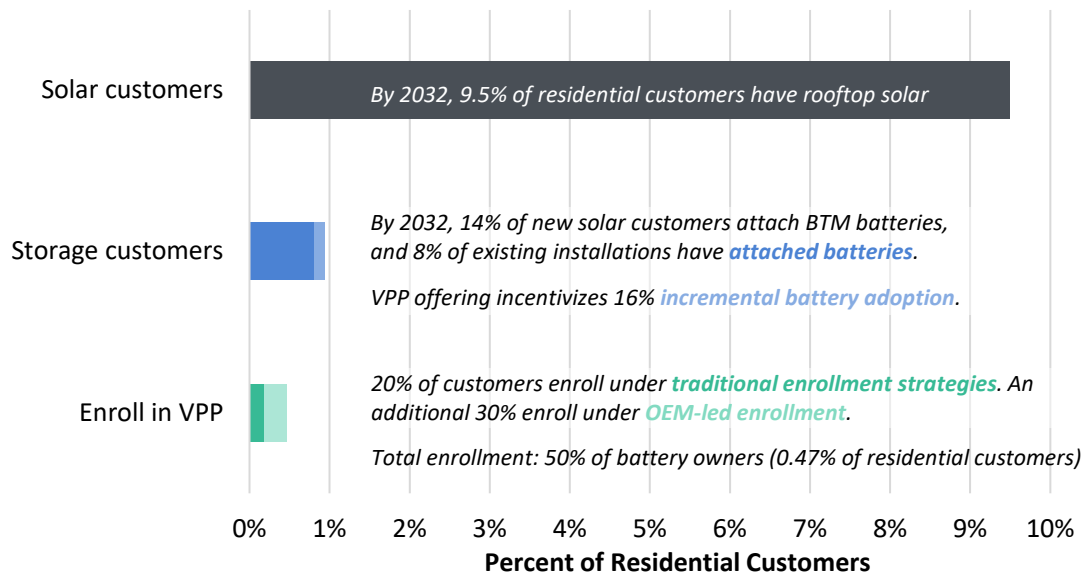
Similar levels of enrollment have been achieved in leading BTM battery VPP programs. The ConnectedSolutions program in Massachusetts and Rhode Island has enrolled over 8,200 Tesla Powerwall batteries as of July 2025—more than 70% of eligible systems.<sup>12</sup> Additionally, OEM-led enrollment approaches have been shown to drive significant growth in VPP participation. In

<sup>11</sup> See Hledik, Peters and Lohiya (2025), [The Demand Side Grid Support Program: An Assessment of Scale and Value](#), prepared for Sunrun and Tesla Energy.

<sup>12</sup> Tesla (2025), [Results: ConnectedSolutions VPP Pay-for-Performance Model](#).

Puerto Rico, Sunrun and Tesla’s auto-enrollment of new battery customers saw VPP participation increase from 12% to over 70% in one year,<sup>13</sup> with 93% of new customers choosing not to opt out of the program.<sup>14</sup> To reflect both of these trends, we assume that 20% of battery owners enroll in the VPP under traditional enrollment strategies, and that an incremental 30% enroll under OEM-led enrollment, bringing total enrollment to 50% or 0.47% of residential customers (see Figure 6).

**FIGURE 6: BTM BATTERY STORAGE VPP ENROLLMENT ASSUMPTIONS**



<sup>13</sup> Brattle correspondence with Sunrun and Tesla.

<sup>14</sup> Sunrun and Tesla (2026), [Joint Motion for Authorization of Additional Auto-Enrollment of Batteries in the Customer Battery Energy Sharing Program for the Summer 2026 Season](#), Case No. NEPR-MI-2026-0002.

## B. Load Reductions per Participant

For each of the technologies in the VPP, we determined the peak load reduction per participant which, when multiplied by the number of participants in each program, gives the total installed capacity of that technology. This value represents the average expected load reduction during a peak load event across a portfolio of VPP participants; importantly, it is not necessarily equal or proportional to the load reduction that each participant can receive accreditation for when determining its capacity value.<sup>15</sup> Table 5 summarizes the per-participant load reductions assumed for this study.

TABLE 5: SUMMARY OF ASSUMED LOAD REDUCTIONS PER PARTICIPANT

| Program                                       | Per-Participant Load Reduction (kW per event) | Justification                                                                                                                                                                                                     |
|-----------------------------------------------|-----------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Smart thermostats (ESC)</b>                | 0.58                                          | Observed average 2-hour load reduction for ESC customers during Everyday Electric 2025 randomized control trials. <sup>16</sup>                                                                                   |
| <b>Smart thermostats (high-impact)</b>        | 0.90                                          | Average 2-hour load reduction reported by Everyday Electric from survey of 10 traditional utility thermostat programs. <sup>17</sup>                                                                              |
| <b>EV managed charging</b>                    | 0.68                                          | 75% of average EV charging demand during 4-hour peak load window (weekday 6–9pm) for non-TOU customers. <sup>18</sup>                                                                                             |
| <b>BTM battery storage (organic adopters)</b> | 3.6                                           | Assumes single battery with average storage capacity equal to the national median of 13.5 kWh according to latest LBNL data. <sup>19</sup> Assumes 20% reservation of storage capacity and 3-hour event duration. |
| <b>BTM battery storage (VPP adopters)</b>     | 7.2                                           | Assumes that VPP adopters install two 13.5 kWh batteries. Assumes 20% storage capacity reservation and 3-hour event duration.                                                                                     |

<sup>15</sup> See Section IV.A for more discussion on capacity accreditation.

<sup>16</sup> Renew Home (2025), [Scaling Residential Demand Response by Prioritizing Comfort: Evidence from 25 Million Energy Shifts](#), whitepaper, Table 1, p. 7.

<sup>17</sup> *Id.*, p. 12.

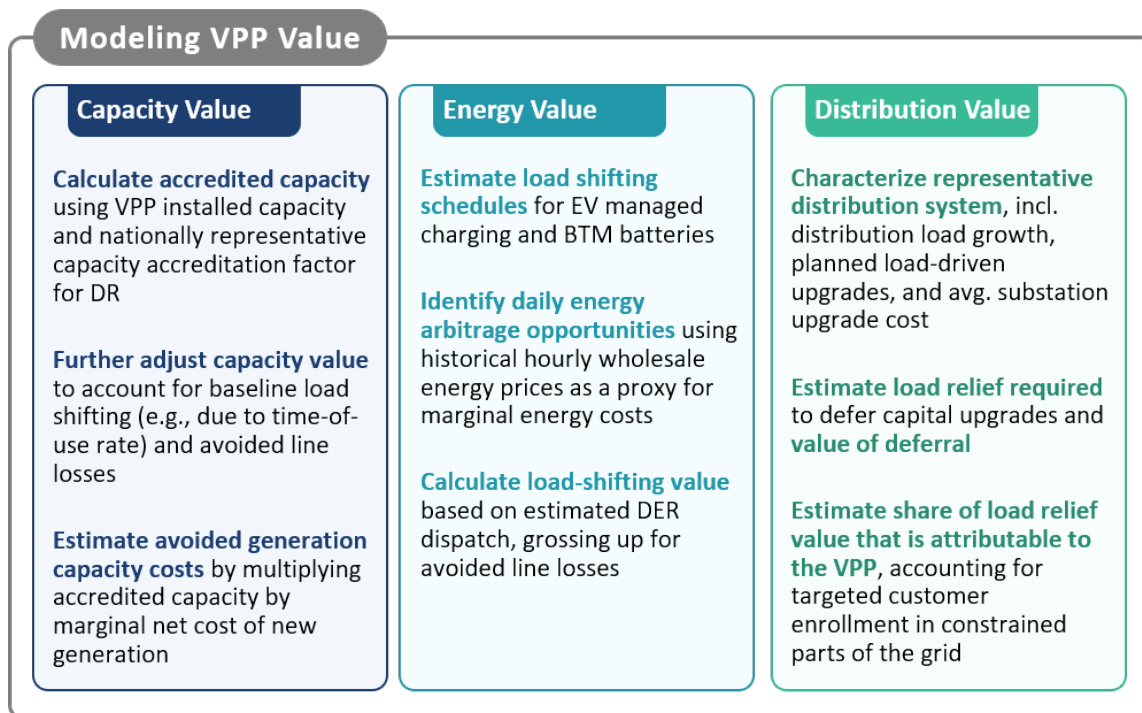
<sup>18</sup> Peak load hours identified for MISO Load Resource Zone 1 using data from Energy Velocity Suite. Charging profile obtained from the U.S. DOE's [EVI-Pro Lite tool](#) for 30,000 EVs in Minneapolis–St. Paul and converted to a per-EV basis.

<sup>19</sup> LBNL (2026), [U.S. Distributed Solar and Storage Data: 2026 Data Update](#).

## IV. Modeling VPP Value

Figure 7 provides an overview of the modeling approach used to estimate the annual value of the VPP. We estimated value as a function of three avoided cost streams: avoided generation capacity costs, avoided energy costs, and deferred distribution upgrade costs. The subsequent subsections detail the methodologies and assumptions used to estimate each value stream.

FIGURE 7: OVERVIEW OF MODELING APPROACH



### A. Capacity Value

The VPP generates capacity value by reducing customer load during peak hours, avoiding the need to invest in additional generation capacity resources to meet peak demand. Additionally, because load reductions at the point of demand reduce the amount of electricity that needs to be transported across the transmission system, the VPP also reduces the amount of electricity lost through line losses. We account for both these value streams by estimating the amount of firm generation capacity that could be avoided by the VPP, accounting for the fact that the VPP does not need to “over-build” in anticipation of line losses in the way that generation does.

When estimating the capacity value of a VPP, some studies apply further adders with the justification that the generation planning process typically applies a planning reserve margin

(PRM) on top of forecasted peak load, and that the VPP avoids the need to procure for this reserve margin. Whether this approach is appropriate depends in part on whether the VPP is being analyzed from the “supply side” or the “demand side”—i.e., whether during planning it is considered a generation resource dispatched once demand forecasts have been determined, or a load-modifying resource that reduces the demand that generation resources must be dispatched to meet. Since we accredit the capacity of the VPP using the same methodology as generation resources—by estimating the amount of new load that could be supported by an additional kilowatt of VPP capacity—we evaluate the VPP’s capacity value as a supply-side resource, and thereby do not apply a PRM adder. In our sensitivity analysis, we include a PRM adder in our “high capacity value” case to evaluate the potential upside of different capacity accreditation approaches.

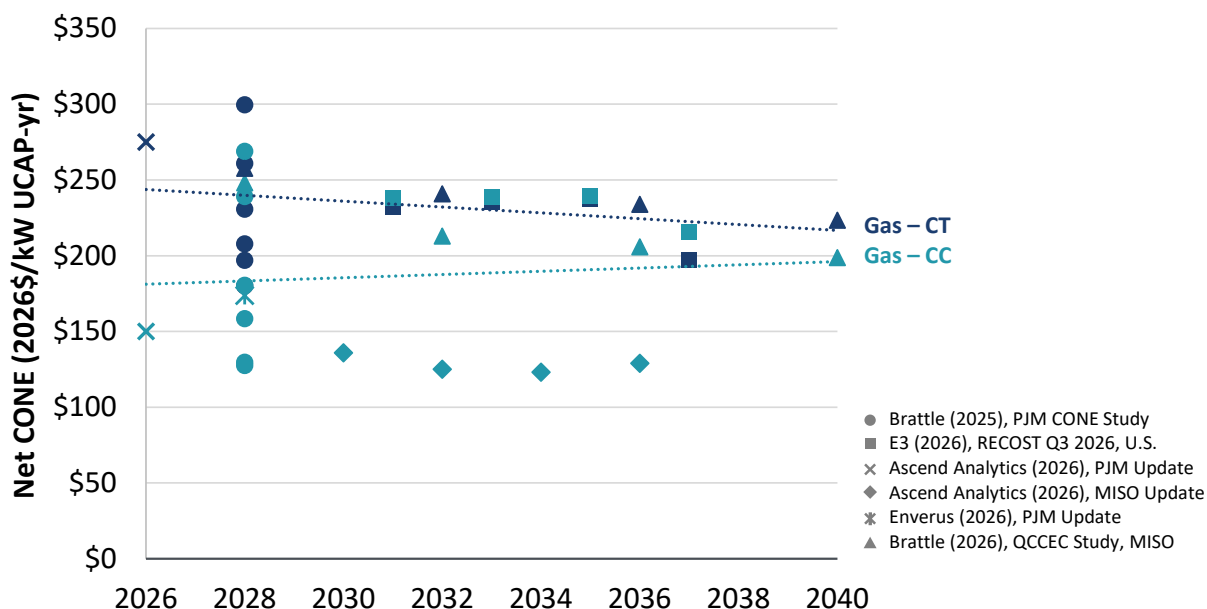
To estimate avoided capacity costs, two important inputs are needed: the marginal cost of generation capacity, and the capacity accreditation factor of the VPP. These are discussed below.

## Marginal Cost of Generation Capacity

The marginal cost of generation capacity represents the cost of adding sufficient generation capacity to support an incremental megawatt of peak demand. A common metric for the marginal cost of capacity is the net cost of new entry (“net CONE”), which represents the annualized fixed revenue requirement that a merchant developer would need in order to justify investing in a new generation asset, net of expected revenues in energy and ancillary service markets. Net CONE is often calculated by system operators in regions with capacity markets, and is often tied to a specific reference technology, typically a single-cycle or combined-cycle gas turbine.

Recent gas turbine supply chain shortages have seen significant increases in near-term projections of overnight capital costs for these assets, which in turn has increased both forecasts of net CONE and uncertainty surrounding these forecasts. While most forecasts anticipate supply chains recovering in the second half of the 2030s, sustained high prices for gas turbines are widely expected for the horizon considered in this study. To inform a reasonable estimate of the marginal cost of generation capacity for the first five years of the VPP’s operation, we conducted a survey of recent net CONE forecasts for MISO and PJM, shown in Figure 8. These estimates are expressed in dollars per kilowatt-year of “unforced capacity” or UCAP (\$/kW UCAP-yr, sometimes referred to as net effective CONE), meaning they incorporate the effective load-carrying capability (ELCC) of the reference resource and therefore represent the cost of using that resource to support an additional kilowatt-year of peak demand.

FIGURE 8: SURVEY OF RECENT NET CONE ESTIMATES FOR MISO AND PJM

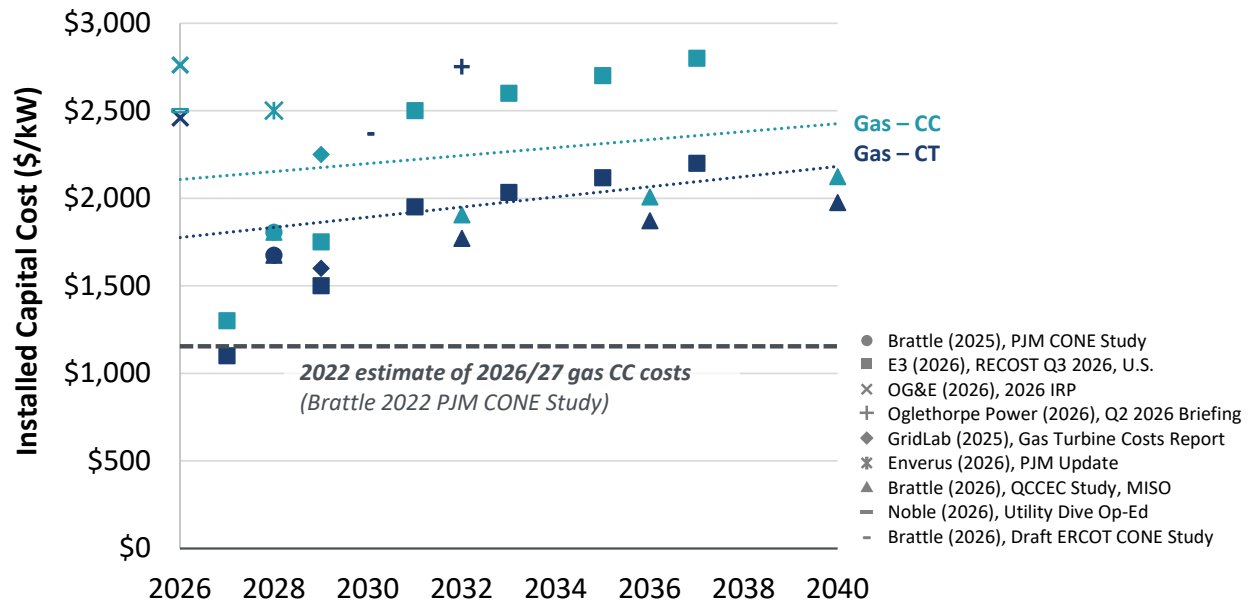


*Sources and Notes:* Estimates from Brattle’s 2025 [PJM CONE Study](#) are based on capital cost trends at the time of the study’s publication across PJM’s Locational Deliverability Areas. To estimate net CONE from E3’s [RECOST Q3 2026 Update](#), we took levelized cost of capacity (LCOC) values at the highest ELCC in the provided range (90% for CTs, 95% for CCs), assumed merchant revenues based on estimates in other studies (\$60/kW-yr for CTs, \$120/kW-yr for CCs), and subtracted derated revenues from the LCOCs. Ascend Analytics data was taken from its 2026 [PJM](#) and [MISO](#) Updates. Enverus net CONE data taken from its July 2026 PJM Market [Report](#). Brattle’s MISO estimates are taken from data from its May 2026 [study](#) on the Quad Cities Clean Energy Center and applying an assumed ELCC of 75%.

The survey shows a wide range of values from approximately \$120/kW-yr to \$300/kW-yr (2026 dollars). We selected a central estimate of \$200/kW-yr as our marginal cost of generation capacity value, and assumed an annual escalation of 1% in real terms to simulate the potential for continued growth across the first five years of the VPP’s operation. For our sensitivity analysis, we assume low and high values of \$140/kW-yr and \$250/kW-yr, respectively.

In addition to net CONE forecasts, we also conducted a survey of the gross CONE forecasts for gas turbines that accompanied them, as well as some other recent benchmarks. These costs are referenced on pages 12 and 13 of Volume I and are summarized in Figure 9 below.

FIGURE 9: RECENT FORECASTS OF GAS TURBINE CAPITAL COSTS



*Sources and Notes:* 2022 baseline estimate from Brattle’s 2022 [PJM CONE 2026/2027 Report](#)—these values are 2022 estimates of gross CONE in the 2026/2027 PJM planning year. Brattle’s most recent cost estimates are from its October 2026 [draft ERCOT CONE Study](#). Estimates from Brattle’s 2025 [PJM CONE Study](#) are based on capital cost trends at the time of the study’s publication across PJM’s Locational Deliverability Areas. E3 data from E3’s [RECOST Q3 2026 Update](#). OG&E data comes from its 2026 [Integrated Resource Plan](#). Data from Oglethorpe Power was estimated using data from its [Second Quarter Investor Briefing](#) where its proposed budget for a 209 MW gas CT plant was \$525–625 million. Gridlab data from its 2025 [Gas Turbine Costs Report](#). Enverus capital cost data taken from its July 2026 PJM Market [Report](#). Brattle’s MISO estimates are taken from data from its May 2026 [study](#) on the Quad Cities Clean Energy Center. Utility Dive quoted EPRI estimates in a [March 2026 opinion piece](#).

In addition to gas turbine costs, we surveyed capital costs for four-hour battery storage and standalone solar. For four-hour storage, we consulted Brattle’s 2025 PJM CONE Study, which estimated 2028 overnight capital costs to vary from \$1,750–\$1,980/kW across PJM’s LDAs. Similarly, 2024 estimates from NREL’s Annual Technology Baseline (ATB) dataset<sup>20</sup> were between \$1,574 and \$2,012/kW. NREL ATB cost estimates for standalone solar ranged from \$1,534 to \$1,576/kW.

## VPP Capacity Accreditation Factor

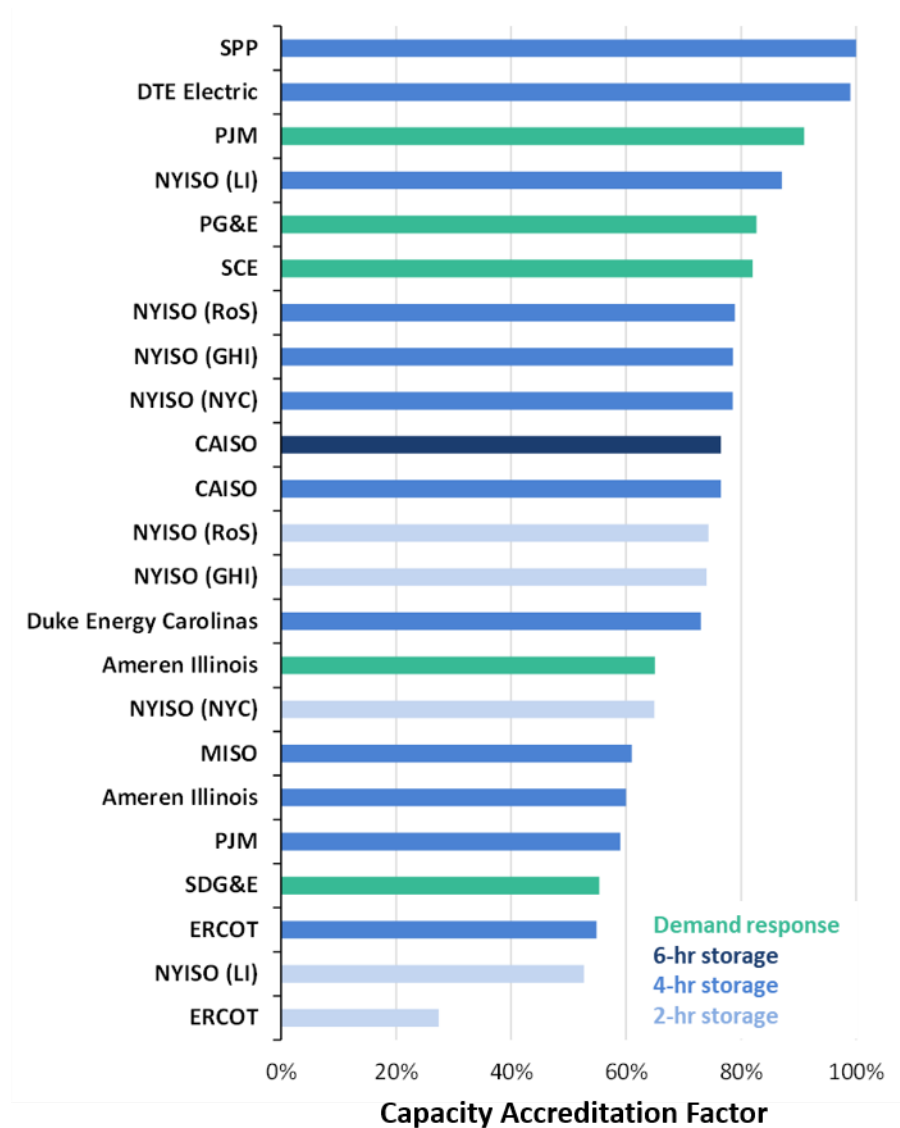
The capacity accreditation factor is used to “derate” the installed capacity of the VPP to represent the share that can be deemed accredited capacity when determining capacity value. We reviewed capacity accreditation factors for energy storage and demand response resources used for capacity accreditation and/or system planning purposes at both RTOs and IOUs. A summary of our review is shown in Figure 10. Since the ability of a resource to support load

<sup>20</sup> National Laboratory of the Rockies, [Annual Technology Baseline](#).

additions is dependent on the penetration of that resource as well as the composition of the rest of the capacity mix, there is significant variety in ELCCs across jurisdictions. MISO and PJM accredit four-hour energy storage at approximately 60%, while PJM accredits demand response at approximately 90%.

In addition to the survey, we conducted simulations across ten years of hourly electricity load data to estimate the ability of the VPP to support load additions under a variety of system and weather conditions. We used hourly load data from 2015 to 2024 for MISO Load Zones 3 and 5, and scaled these data to obtain an average weather-normalized peak load of 7,000 MW (the peak demand of our illustrative utility) across the ten years. For each weather year, we used Brattle’s in-house VPP dispatch optimization simulation model to minimize peak load across the year, and compared the reduction in peak load to the installed capacity of the VPP to estimate the capacity credit it would have received in that year. Our model accounts for the operational constraints of DERs, including resource-specific limitations on the frequency and duration of VPP events. Everyday Electric dispatches its ESC customers for up to 100 hours per year—therefore, for ESC smart thermostat participants, we assumed three-hour events and a maximum of 20 events per year. For high-impact smart thermostat customers, we assumed four-hour events and a maximum of 25 events per year. EV managed charging was assumed to have daily four-hour events. For simplicity, we did not model interactions with TOU rates.

FIGURE 10: SURVEY OF CAPACITY ACCREDITATION FACTORS ACROSS JURISDICTIONS



Sources and Notes: MISO values from MISO (2025), [Direct Loss of Load \(DLOL\) Results for Planning Year](#). CAISO values from E3 (2023), [Incremental ELCC Study for Mid-Term Reliability Procurement](#), prepared for CPUC. PG&E, SCE and SDG&E values from E3 (2021), [Demand Response ELCC Study](#), prepared for CAISO, p. 28. Ameren Illinois values from CRA (2023), [Ameren Illinois RTO Cost-Benefit Study](#). PJM values from PJM (2026), [ELCC Class Ratings for the 2028/2029 Base Residual Auction](#). NYISO values from NYISO (2025), [2025-2026 Final Capacity Accreditation Factors](#). ERCOT values from Astrape Consulting (2025), [ELCC Study](#). SPP values from SPP (2026), [2026 Effective Load Carrying Capability Study Report](#). Duke Energy Carolinas results from PowerGEM (2025), [ELCC Report](#). DTE Electric results from Astrape Consulting (2022), [DTE Electric Resource Adequacy and LR27 ELCC Assessments](#).

When determining the load reduction achieved by the VPP in a given weather year, we measured reductions from the larger of the observed peak in that year and the “planning peak” demand of 7,000 MW. Since the load data were scaled to ensure an average peak demand of 7,000 MW across the ten years, they represent a reasonable expectation of a variety of conditions that the VPP could expect to face in a given planning year, with some years having

peaks greater than 7,000 MW and some having peaks below 7,000 MW. When estimating the capacity value of the VPP from a planning perspective, we characterize the accredited capacity of the VPP as the load reduction the VPP is being compensated for reliably delivering in an average year. Under this framing, in years with below-average peak demand, less load reduction is required to keep the system within acceptable conditions, despite the VPP being available to deliver additional peak shaving; in these cases, it is appropriate to measure the VPP's load reduction against the 7,000 MW planning peak to account for this availability. In years with above-average peak demand, measuring against planning peak is no longer appropriate, since this would result in artificially low or even negative capacity accreditation factor even if the VPP was able to reduce load by 100% of its installed capacity; in these cases, we measured the accredited load reduction as the absolute load reduction achieved by the VPP.

Table 6 provides summary statistics of the load reduction requirements across each weather year as well as the capacity accreditation factor achieved by the VPP in our modeling. Across the ten weather years, the average capacity accreditation factor achieved by the VPP was 76%, with values ranging from 53% to 100%. High capacity credits were not necessarily correlated with above- or below-average peak demand, but rather with the maximum duration of required load reductions. For example, in 2024, the VPP was able to receive capacity credit for 100% of its installed capacity despite the system peak being 118 MW higher than the planning peak; maximum load reduction duration during this year was five hours. By contrast, the VPP only earned a 58% capacity credit in 2016, which only required a 263 MW load reduction to achieve 100% capacity accreditation but had a maximum load reduction duration of six hours.

**TABLE 6: LOAD REDUCTION CHARACTERISTICS AND CAPACITY ACCREDITATION FACTOR RESULTS ACROSS YEARS**

| Year        | System Peak (MW) | Load Reduction Requirements at 100% Capacity Accreditation |                       |                      |                                 | Achievable Capacity Credit |
|-------------|------------------|------------------------------------------------------------|-----------------------|----------------------|---------------------------------|----------------------------|
|             |                  | Peak Reduction (MW)                                        | Total reduction hours | Total reduction days | Max consecutive reduction hours |                            |
| 2015        | 7,042            | 301                                                        | 9                     | 3                    | 6                               | 68%                        |
| 2016        | 6,962            | 263                                                        | 7                     | 2                    | 6                               | 58%                        |
| 2017        | 7,004            | 301                                                        | 10                    | 2                    | 6                               | 58%                        |
| 2018        | 6,904            | 205                                                        | 16                    | 5                    | 5                               | 100%                       |
| 2019        | 6,983            | 284                                                        | 10                    | 2                    | 6                               | 61%                        |
| 2020        | 6,760            | 61                                                         | 2                     | 1                    | 2                               | 100%                       |
| 2021        | 6,880            | 181                                                        | 20                    | 6                    | 5                               | 100%                       |
| 2022        | 6,993            | 294                                                        | 24                    | 8                    | 6                               | 53%                        |
| 2023        | 7,354            | 301                                                        | 20                    | 4                    | 6                               | 61%                        |
| 2024        | 7,118            | 301                                                        | 26                    | 6                    | 5                               | 100%                       |
| <b>Avg.</b> | 7,000            | 249                                                        | 14                    | 4                    | 5                               | <b>76%</b>                 |

Based on both the jurisdictional survey and the modeling described above, we assumed a capacity accreditation factor of 75% for the VPP. This factor was applied evenly across resources in the VPP, with the exception of BTM battery storage and EV managed charging participants enrolled in TOU rates. Since these customers already receive price signals to shift their load outside of peak hours, we assumed they are only able to receive a fraction of the VPP-wide capacity accreditation factor. We assumed that battery customers on TOU rates received 80% of the VPP-wide capacity credit (i.e., a capacity accreditation factor of 60% rather than 75%). For EV managed charging, we used findings from Brattle’s 2026 EV Managed Charging report with EnergyHub to estimate tradeoffs with TOU rates.<sup>21</sup> We assumed customers on TOU rates received 15% of the capacity credit received by non-TOU customers (i.e., a capacity accreditation factor of 11%) but twice the distribution value as non-TOU customers, since TOU-based shifting of EV charging load can exacerbate distribution constraints, and enrolling these customers would therefore provide greater distribution system relief than enrolling non-TOU customers. These derates to BTM battery storage and EV managed charging customers bring the effective capacity accreditation factor of the whole VPP to 70%.

Finally, since the VPP reduces load at the distribution level, it also avoids line losses that would otherwise have been incurred when transmitting electricity from traditional generators to the distribution grid. Therefore, we grossed up our capacity value estimates by an assumed line loss rate of 8%.

## B. Energy Value

We estimated energy value for EV managed charging and BTM battery storage, since these resources are capable of regular load shifting out of high energy-price hours. To perform this analysis, we used hourly day-ahead locational marginal price (LMP) data from 2025 at MISO’s Minnesota Hub as well as 2025 hourly net load data from MISO Load Resource Zone 1.<sup>22</sup>

For EV managed charging, we assumed that EV charging load was shifted daily to avoid high-price hours, with 75% of charging load between 2 p.m. and midnight being shifted to “overnight” hours between midnight and 5 a.m. For each day in our hourly LMP dataset, we calculated the load shift per EV in kWh/EV (based on weekday and weekend average charging profiles obtained from the DOE’s EVI-Pro Lite tool), the additional “overnight” energy costs

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<sup>21</sup> Ramakrishnan et al. (2026), [Demonstrating the Full Value of Managed Electric Vehicle Charging](#), prepared for EnergyHub.

<sup>22</sup> Load and LMP data sourced from Energy Velocity Suite.

incurred by shifting load into those hours per EV, and the energy costs avoided per EV by shifting load out of peak hours. The difference between the avoided charging costs and incurred overnight charging costs gave the avoided energy costs per EV for the given day; we then grossed up by 8% to account for avoided line losses.

For BTM battery storage, for each day we calculated the average difference between the two highest-priced hours and two lowest-priced hours of that day, and multiplied this by the average available battery storage capacity to estimate daily energy arbitrage value in dollars per customer, grossing up to account for avoided line losses. We then looked across the year and selected the 100 days with the highest energy arbitrage value, since we limited battery dispatch to 100 days per year, and summed across the year to estimate annual energy value per enrolled BTM battery.

## C. Distribution Value

DERs generate distribution value by reducing load on constrained parts of the distribution system so that planned upgrades to alleviate the constraint are deferred or avoided entirely—the value of avoiding these costs through load reduction is called “deferral value”. In reality, distribution value is highly dependent on the specific characteristics of the distribution system; distribution grids vary widely in terms of the number of constrained distribution assets in the utility’s forecasts, the timing of distribution system peaks, the cost of capital upgrades required to mitigate overloads on constrained assets (sometimes referred to as the marginal cost of distribution system capacity), and the current and potential penetration of DERs on the grid. Even within the same distribution system, these variables can vary widely across distribution assets. To accurately calculate the deferral value of a VPP therefore requires detailed data on the specific utility system in question—including hourly load forecasts and present and future DER penetrations—and it is difficult to generalize the deferral opportunity of DERs from one utility to another.

In this study, we did not have access to such detailed data. We therefore took a more generalized approach to serve as a reasonable approximation of the value that VPPs can provide to an illustrative utility system, acknowledging that actual distribution value will vary from these estimates considerably.

We estimated the distribution value of the VPP by estimating the load relief required to defer distribution capital upgrades, the value of that deferral, and the share of that value that is attributable to the VPP. Where it was necessary to characterize our representative utility’s

distribution system, we used DTE Electric as a reference. Table 7 outlines the general modeling approach for distribution value in this study.

**TABLE 7: OVERVIEW OF DISTRIBUTION VALUE MODELING APPROACH**

| Step                                                                                                     | Sources & Notes                                                                                                                                                                                                                             |
|----------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| 1 Forecast the number of overloaded substations in each year from the first year of VPP operation (2032) | We assumed the share of overloaded substations followed that laid out in DTE Electric's 2026 Distribution Grid Plan (DGP). <sup>23</sup>                                                                                                    |
| 2 Estimate the load relief capability of the VPP with targeted enrollment                                | DER MWs on constrained substation multiplied by distribution load reduction accreditation factor. Assume participants are unevenly located in constrained parts of the distribution grid through the use of targeted enrollment incentives. |
| 3 Characterize the average deferral opportunity (upgrade cost, deferral length)                          | Based on average cost of system loading upgrades in DTE's DGP and assumptions on deferral length.                                                                                                                                           |
| 4 Calculate the annualized cost of upgrades without the VPP                                              | Number of constrained substations multiplied by annualized upgrade cost                                                                                                                                                                     |
| 5 Calculate the annualized cost of deferred upgrades with the VPP                                        | Same data series, lagged by the number of years of deferral.                                                                                                                                                                                |
| 6 Calculate the load relief needed to achieve the assumed level of deferral                              | Total MWs of overload across constrained substations according to assumed rate of load growth.                                                                                                                                              |
| 7 Calculate the share of the necessary load relief that could be provided by VPP                         | VPP load relief capability divided by total load relief need.                                                                                                                                                                               |
| 8 Allocate annualized cost savings according to the share of load relief provided by VPP                 | VPP load relief share multiplied by the difference between 4 and 5.                                                                                                                                                                         |

For Step 1, we assumed the share of overloaded substations followed that laid out in DTE Electric's 2026 DGP. As of 2026, DTE Electric had 702 distribution substations with a total substation capacity of 37,870 MVA;<sup>24</sup> we were therefore able to estimate the incremental number of overloaded substations each year from the first year of the VPP's operation (2032).

For Step 2, we assumed that VPP enrollment was targeted towards households located on constrained parts of the distribution system. We did not assume that all VPP participants are located on constrained substations; instead, we assumed that targeted enrollment resulted in there being 2.5 times as many VPP participants on constrained substations as there would have been if VPP participants were evenly spread across all 702 substations. This assumption was

<sup>23</sup> DTE Electric (2026), [Distribution Grid Plan](#), Ex. 2.6, p. 19.

<sup>24</sup> DTE Electric (2026), [SEC Form 10-K](#).

informed by experience in Connecticut’s Energy Storage Solutions (ESS) program, which offers an incentive adder to residential customers located on circuits in the top 10% for number of outages per customer during major storms and/or the top 10% for duration of major-storm outages (referred to as “Grid Edge” customers).<sup>25</sup> Latest data indicates that 596 of 1,948 completed or approved residential projects (roughly 30%) were located in Grid Edge areas.<sup>26</sup> Using this assumption, we calculated the total amount of installed DER capacity at each constrained substation.

To estimate the load relief each DER could provide, we derated installed capacity by multiplying by a distribution load reduction accreditation factor of 50% for EV managed charging and BTM batteries and 25% for smart thermostats. These accreditation factors were based on prior Brattle analysis using detailed utility data comparing the coincidence between distribution substation four-hour peaks and daily LMP peaks on the wholesale energy market, which found that around 50% of distribution peaks were aligned with high-priced energy market hours throughout the year. A battery or EV managed charging resource shifting its load to provide daily bulk system value could therefore reasonably be expected to provide distribution load relief across 50% of distribution peak periods. We further derated smart thermostats based on additional analysis conducted using detailed distribution system data from another utility, which found that when co-optimizing between bulk system and distribution system dispatch, DR resources such as smart thermostats were able to achieve half as many hours of load reduction as BTM batteries.

For Step 3, we assumed an average substation upgrade cost of \$20 million based on the average five-year cost for planned system loading upgrades in DTE Electric’s 2026 DGP.<sup>27</sup> Given recent trajectories of rising distribution equipment costs, we assumed that substation upgrade costs increase by 2% in real terms per year. We assumed an average deferral length of five years based on previous Brattle modeling.<sup>28</sup> We benchmarked these assumptions against a survey proposed and awarded deferral projects outlined in non-wires solutions (NWS) RFPs; this comparison is presented in Figure 11. The difference between the values in Steps 4 and 5 represents the annual value of achieving the deferral characteristics assumed in Step 3.

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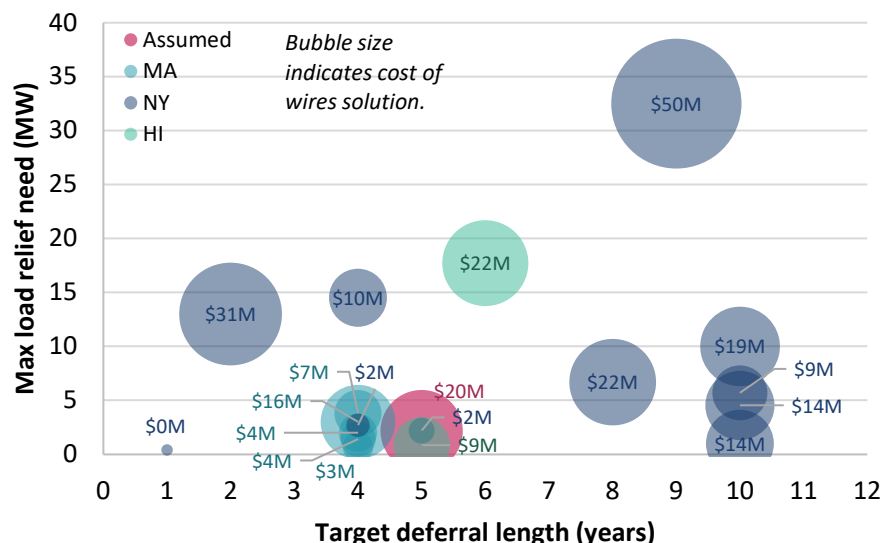
<sup>25</sup> Energy Storage CT (2026), [Grid Edge Map instructions](#).

<sup>26</sup> Energy Storage CT (2026), [Energy Storage Solutions Performance Report](#). Assuming that 12% of residential customers are located on one of the two top-10% qualifying circuits,  $30\% / 12\% = 2.5$  times as many Grid Edge customers as if battery projects were evenly distributed across circuits.

<sup>27</sup> DTE Electric (2026), [Distribution Grid Plan](#), Ex. 6.47, p. 233.

<sup>28</sup> Sergici et al. (2026), [The Value of Using DERs for Distribution System Services in Ontario](#), prepared for Clean Energy Canada, p. 17.

**FIGURE 11: COMPARISON BETWEEN ASSUMED DEFERRAL CHARACTERISTICS AND THOSE OBSERVED IN NWS SOLICITATIONS**



For Step 6, we estimated the load relief required to achieve the assumed level of deferral by first estimating the average substation capacity of DTE Electric’s system (54 MVA<sup>29</sup>), then estimating a reasonable rate of distribution system load growth, then estimating the rate of average per-substation annual load growth in MVA/yr, and finally estimating the total required load relief to avoid overloading the constrained substations in each year. We assumed a distribution load growth rate of 0.8% per year based on MISO’s Long-Term Load Forecast, assuming that 40% of manufacturing load and 5% of data center load were distribution-connected.<sup>30</sup>

In Steps 7 and 8, the portion of required load relief provided by the VPP was calculated, and that share was multiplied by the annual value of deferring the required upgrades to estimate the share of total deferral value attributable to the VPP. In this way, our estimate of distribution value envisages the VPP as part of a broader suite of measures to defer capital upgrades (e.g., alongside front-of-meter distributed batteries), rather than being able to defer the upgrades entirely on its own.

<sup>29</sup> 37,870 MVA / 702 distribution substations = 54 MVA per substation.

<sup>30</sup> MISO (2026), [2026 Long-Term Load Forecasting \(LTLF\) Results Summary](#).

## V. Calculating Financial Benefits to Consumers

Once the total value generated by the VPP was calculated, we estimated the share of this total value that goes to consumers in the form of net system cost savings (that ultimately put downward pressure on electricity rates) and direct performance payments to VPP participants.

We first estimated total VPP implementation costs. These costs cover marketing expenses, incremental device integration and/or software fees, and other administrative costs required to set up and run the VPP program. Based on review of program budgets across jurisdictions, we assumed an average implementation cost of \$30/kW-yr.

We then subtracted implementation costs from the total value stack to estimate the total financial benefit to consumers. A portion of these system cost savings is paid to VPP participants in the form of performance payments, while the remainder was assumed to flow through to residential electricity rates and therefore accrue to all residential customers. Across all programs, we assumed a performance payment of \$75/kW-yr. Since different technologies provide different degrees of value (see Section III of Volume I), typical performance payment levels vary by program—our assumed value is a weighted average of the performance payments across our smart thermostat, EV managed charging, and BTM battery storage programs. As summarized in Table 8, we assumed a \$50/kW-yr performance payment for smart thermostats, a \$150/kW-yr payment for EV managed charging, and a \$200/kW-yr payment for BTM battery storage.

TABLE 8: ASSUMED INCENTIVE LEVELS BY PROGRAM

| Program                 | Installed Capacity | Performance Payment | Source                                                                                                                                                                                                                                                                                              |
|-------------------------|--------------------|---------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Smart thermostat        | 236 MW             | \$50/kW-yr          | Weighted average across a survey of prominent smart thermostat programs at Duke Energy, PG&E, SCE, APS, Consumers Energy, PGE, CPS Energy and SRP. Based on a survey of incentive levels in 10 prominent BTM battery storage programs and three prominent residential EV managed charging programs. |
| EV managed charging     | 44 MW              | \$150/kW-yr         |                                                                                                                                                                                                                                                                                                     |
| BTM battery storage     | 21 MW              | \$200/kW-yr         |                                                                                                                                                                                                                                                                                                     |
| <b>Weighted average</b> | <b>301 MW</b>      | <b>\$75/kW-yr</b>   |                                                                                                                                                                                                                                                                                                     |

## VI. Modeling Affordability Impacts

To model how the value created by the VPP impacts household electricity bills, we took the following steps:

- We projected all-in residential electricity rates out over five years (roughly to 2032) assuming annual rate growth of 1% in real terms based on a survey of recent and projected trends of residential rate growth. We assumed a 2026 rate of 16.5 c/kWh, roughly equal to the median all-in residential electricity rate across U.S. investor-owned utilities (IOUs).<sup>31</sup>
- We multiplied the average annual residential electricity consumption value outlined in Section II by the projected rate in each year to calculate projected average household electricity bills by year.
- To estimate the annual value provided by the VPP to the average household, we assumed that all value flowed through to the residential customer class. This is broadly consistent with the cost-causation principles used in ratemaking, since the VPP lowers residential peak demand while leaving C&I peak demand unchanged. We therefore divided the total annual value created by the VPP (net of implementation costs) by the number of residential customers to determine the annual avoided costs per customer.
- To estimate the annual value specifically for non-participants, we subtracted performance payments from the value above. To estimate the annual value specifically for participants, we divided the total performance payments per year by the number of participants, assuming that 10% of participants participate with more than one DER.

## VII. Sensitivity Analysis

To conduct the sensitivity analysis, we replicated the affordability impact calculations above across a range of assumed values for a shortlist of impactful variables. We bundled these variables into five “buckets”—technology adoption, VPP enrollment, capacity value, distribution value, and implementation cost—and evaluated the bill impacts across the high and low values in each of these buckets. Table 9 summarizes the sensitivity cases evaluated in this study—each of the panels in the table represents one bucket.

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<sup>31</sup> We estimated the median residential rate by comparing the median and mean all-in residential electricity rates across IOUs in 2024 per EIA-861 data, and used the ratio between them and the latest EIA average residential rate data to estimate the median rate across IOUs in 2026.

TABLE 9: SUMMARY OF SENSITIVITY ANALYSIS ASSUMPTIONS

| Input Variable                                           | Case    | Value | Notes                                                                                                                                                   | Source                                                                  |
|----------------------------------------------------------|---------|-------|---------------------------------------------------------------------------------------------------------------------------------------------------------|-------------------------------------------------------------------------|
| <b>Technology adoption</b>                               |         |       |                                                                                                                                                         |                                                                         |
| <b>EV penetration</b><br>(% of LDVs)                     | Current | 11%   | Lower than the 5-yr projected U.S. average (13%) to distinguish from strong/outlier EV markets (e.g., CA); accounts for OBBBA-related headwinds         |                                                                         |
|                                                          | Low     | 6%    | Enverus Intelligence Research U.S.-average forecast from June 2026 accounting for slowdown due to OBBBA.                                                | <a href="#">EIR (2026), EV Adoption Forecast</a>                        |
|                                                          | High    | 15%   | Above EIA AEO 2026 nationwide projections; implies policy interventions to further stimulate adoption.                                                  | <a href="#">EIA (2026), 2026 Annual Energy Outlook</a>                  |
| <b>Smart thermostat penetration</b> (% of CAC)           | Current | 60%   | Assumed with input from Everyday Electric.                                                                                                              |                                                                         |
|                                                          | Low     | 50%   | Assumed                                                                                                                                                 | -                                                                       |
|                                                          | High    | 70%   | Assumed                                                                                                                                                 | -                                                                       |
| <b>Solar penetration</b> (% of households)               | Current | 9.5%  | Below recent 5-yr projections from strong Midwestern solar markets (e.g., 12% in IL), to account for OBBBA-related headwinds.                           |                                                                         |
|                                                          | Low     | 6%    | Half of Ameren IL IGP                                                                                                                                   | <a href="#">Ameren IL Integrated Grid Plan (2026), Table 29, p. 163</a> |
|                                                          | High    | 12%   | Value reported in Ameren IL 2026 Integrated Grid Plan (IGP)                                                                                             | <a href="#">Ameren IL Integrated Grid Plan (2026), Table 29, p. 163</a> |
| <b>Storage attachment rate</b> (% of new solar installs) | Current | 14%   | 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 NEM reform | <a href="#">LBNL (2026), U.S. Distributed Solar and Storage Data</a>    |
|                                                          | Low     | 10%   | Roughly middle of the range of 2025 attachment rates amongst sampled Midwestern states.                                                                 | <a href="#">LBNL (2026), U.S. Distributed Solar and Storage Data</a>    |
|                                                          | High    | 17%   | 2025 average across all states excl. CA.                                                                                                                | <a href="#">LBNL (2026), U.S. Distributed Solar and Storage Data</a>    |
| <b>Enrollment</b>                                        |         |       |                                                                                                                                                         |                                                                         |
| <b>EV enrollment</b> (% of EVs)                          | Current | 30%   | Assumes 15% on TOU rates and 15% on non-TOU rates.                                                                                                      |                                                                         |
|                                                          | Low     | 20%   | Assumes 10% on TOU rates and 10% on non-TOU rates.                                                                                                      |                                                                         |
|                                                          | High    | 40%   | Assumes 15% (current level) on TOU rates and 25% on non-TOU rates.                                                                                      |                                                                         |
| <b>Smart thermostat enrollment</b> (% of STs)            | Current | 83%   |                                                                                                                                                         |                                                                         |
|                                                          | Low     | 70%   | Assumes only 50% (as opposed to 70%) of existing customers enroll in VPP.                                                                               |                                                                         |
|                                                          | High    | 90%   | Assumes opt-out enrollment.                                                                                                                             |                                                                         |
| <b>Storage enrollment</b> (% of storage installations)   | Current | 50%   |                                                                                                                                                         |                                                                         |
|                                                          | Low     | 20%   | Assuming no OEM-led enrollment effects.                                                                                                                 |                                                                         |
|                                                          | High    | 80%   | Assuming aggressive OEM-led enrollment such as Sunrun's opt-out program in Puerto Rico.                                                                 |                                                                         |

| Capacity Value                                         |         |       |                                                                                                               |                                                                                             |
|--------------------------------------------------------|---------|-------|---------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------|
| <b>Net CONE</b><br>(\$/kW UCAP-yr)                     | Current | \$200 | Includes some consideration of near-term gas turbine supply chain constraints.                                |                                                                                             |
|                                                        | Low     | \$140 | Assumes gas CT supply chain constraints are alleviated by 2032.                                               | -                                                                                           |
|                                                        | High    | \$250 | Assumes persistence/exacerbation of gas turbine supply constraints.                                           |                                                                                             |
| <b>Capacity accreditation factor (%)</b>               | Current | 75%   | Center of range in ELCC survey; average value across 10 weather years of simulated VPP dispatch.              |                                                                                             |
|                                                        | Low     | 60%   | 10th percentile of the ELCCs obtained across 10 weather years of data; equal to MISO's ELCC for 4-hr storage. | <a href="#">MISO (2025), Planning Year 2025-2026 Indicative Direct Loss of Load Results</a> |
|                                                        | High    | 90%   | ELCC awarded to DR in PJM; modeling found 100% ELCC was possible in some years.                               |                                                                                             |
| <b>Reserve margin gross-up (% additional capacity)</b> | Current | 0%    |                                                                                                               | -                                                                                           |
|                                                        | Low     | 0%    |                                                                                                               | -                                                                                           |
|                                                        | High    | 15%   | Assumes a planning reserve margin of 15%, increasing the accredited capacity of the VPP.                      | -                                                                                           |
| Distribution Value                                     |         |       |                                                                                                               |                                                                                             |
| <b>Distribution load growth rate (%)</b>               | Current | 0.8%  | Derived from review of MISO LTLF.                                                                             |                                                                                             |
|                                                        | Low     | 0.6%  | Low end of range derived from MISO LTLF when excluding data center or emerging manufacturing load.            |                                                                                             |
|                                                        | High    | 1.0%  | High end of range derived from MISO LTLF.                                                                     |                                                                                             |
| Implementation Cost                                    |         |       |                                                                                                               |                                                                                             |
| <b>Implementation costs (\$/kW-yr)</b>                 | Current | \$30  | Assumed based on prior Brattle experience.                                                                    |                                                                                             |
|                                                        | Low     | \$25  | Assumed based on prior Brattle experience.                                                                    |                                                                                             |
|                                                        | High    | \$40  | Assumed based on prior Brattle experience.                                                                    |                                                                                             |