Real Reliability:
The Value of Virtual Power

VOLUME II: TECHNICAL APPENDIX

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Brattle

Disclaimer

PLEASE NOTE

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I. Introduction

This study assessed the cost of serving a utility's new resource adequacy needs from a virtual power plant (VPP). Specifically, we compared the net cost of providing resource adequacy from three resource types: a gas peaker, a transmission-connected utility-scale lithium-ion battery, and a VPP.

We describe the findings of our study in our Volume I summary report. Highlights of the findings include:

- A VPP that leverages residential load flexibility could perform as reliably as conventional resources and contribute to resource adequacy at a similar scale.
- Excluding societal benefits (i.e., emissions and resilience), the net cost to the utility of providing resource adequacy from the VPP is only roughly 40% to 60% of the cost of the alternative options. Extrapolating from this observation, a 60 GW VPP deployment could meet future resource adequacy needs at a net cost that is $15 billion to $35 billion lower than the cost of the alternative options over the ensuing decade (undiscounted 2022 dollars).
- When accounting for additional societal benefits, the VPP is the only resource with the potential to provide resource adequacy at a negative net cost. 60 GW of VPP could provide over $20 billion in additional societal benefits over a 10-year period.
- Key barriers must be addressed to fully unlock this value for consumers.

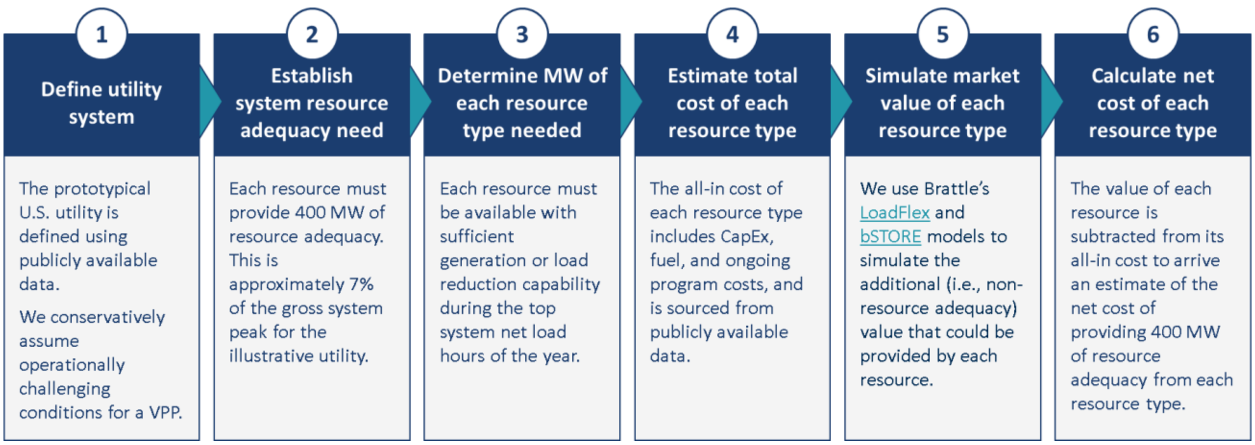
Our study is novel in its combination of a detailed approach to defining the resource adequacy performance requirements of VPPs with a comparative economic assessment of alternative resources that could provide the same resource adequacy. Among other studies that have evaluated the economics and potential of VPPs and load flexibility, RMI recently identified 60 GW of VPP potential by 2030[1] and also separately concluded that renewables, customer-managed load, and battery storage are more cost-effective than long-term gas plant

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

investments.[2] Prior analyses by Brattle[3] and the National Renewable Energy Laboratory (NREL)[4] both identified 200 GW of load flexibility potential in the U.S.

This Volume II report is a technical appendix designed to accompany our Volume I summary report. This technical appendix outlines the assumptions and data sources we used to model the illustrative utility system and associated costs and system impacts of the gas peaker, utility-scale lithium-ion battery, and VPP. Figure 1 provides an overview of our methodology.

FIGURE 1: METHODOLOGY OVERVIEW



II. The Illustrative Utility System

We modeled an illustrative mid-size utility with 400 MW of new resource adequacy need, using public data from actual U.S. utilities wherever possible.

System Load

We based the hourly system load shape on a 2030 forecast from NREL's Cambium 2022 dataset.[5] We used NREL's "Mid-Case 95 by 2035 Scenario" to represent the load conditions of

2 Shwisberg, Lauren and Mark Dyson, "Report Release: Headwinds for US Gas Power," RMI, 2021, https://rmi.org/report-release-headwinds-for-us-gas-power/

3 Hledik, Ryan, Ahmad Faruqui, and Tony Lee, "The National Potential for Load Flexibility," Brattle report, June 2019, https://www.brattle.com/wp-content/uploads/2021/05/16639_national_potential_for_load_flexibility_-_final.pdf

4 Zhou, Ella and Trieu Mai, Electrification Futures Study: Operational Analysis of U.S. Power Systems with Increased Electrification and Demand-Side Flexibility," NREL report, May 2021.

5 Gagnon, Pieter, Brady Cowiestoll, and Marty Schwarz, "Cambium 2021 Data," National Renewable Energy Laboratory, 2022, https://scenarioviewer.nrel.gov

an aggressively decarbonizing system. The hourly load profile was scaled to a system peak of 5,714 MW to represent a mid-sized investor-owned utility.[6]

Customer Base

We assumed the utility has 1.75 million residential customers. This customer count is consistent with the range of system load characteristics (annual energy and peak) and annual load-to-customer ratios from a sample of 52 U.S. investor-owned utilities, according to data from Form EIA-861.[7]

Renewable Generation

We subtracted forecasted hourly renewable generation from hourly gross load in order to determine the utility's hourly net load. Resource planners commonly use net load as the basis for new capacity needs, given the growing market penetration of non-dispatchable wind and solar generation across the U.S. We use net load in the analysis to identify system peak hours and operational needs for new capacity.

Hourly solar and wind generation profiles come from the NREL Cambium Mid-Case "95 by 2035" scenario for balancing area 34.

We scaled the hourly renewable generation profiles to represent 50% of the utility's annual load being served by renewable generation, with a ratio of 25% solar, 75% wind. Many states, on average, have policy goals targeting 50% renewable by 2030.[8] We considered alternative renewable market penetration in a sensitivity case.

Net Load Profiles

System planners make resource investment and demand planning decisions around net peak load. Net load accounts for all load not met by renewable generation that must be met by dispatchable generation, storage, or customer demand management measures.

As shown in Figure 2 below, the simulated utility net load profile (in orange) falls within the range of net load profiles of other balancing areas (when assuming a similar level of renewable

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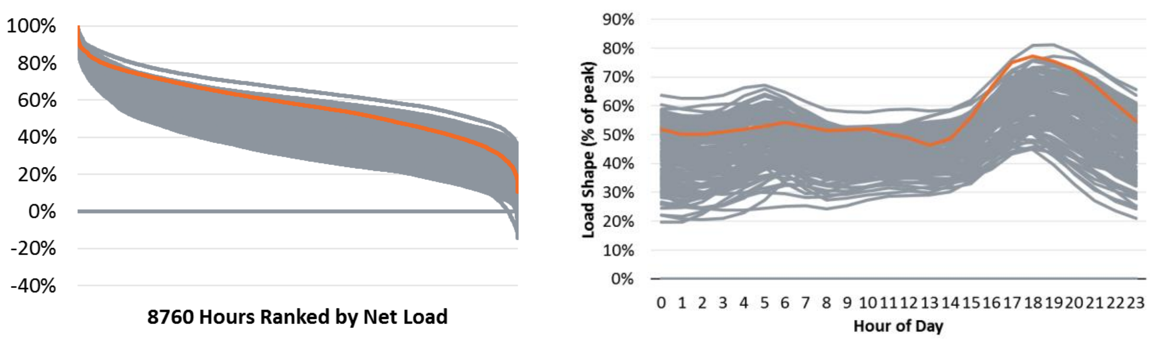
6 Specifically, we used balancing area 34 (in the Rocky Mountain West region). As noted below, we selected this balancing area because its load conditions represented more challenging conditions for VPP resource adequacy performance.

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

8 Barbose, Galen L., U.S. Renewables Portfolio Standards 2021 Status Update: Early Release, 2021.

penetration). However, our modeled utility's annual load shape is flatter than some of the other considered regions. We selected a region with this profile because its characteristics create a need for resource performance in many hours throughout the year (63 hrs) in order to fully provide 400 MW of resource adequacy. A "peakier" load profile, one with peak net load concentrated in a smaller window, may only need dispatch or demand response (DR) in a few hours of the year to achieve 400 MW of resource adequacy. We wanted to explore a case that tested the limits of VPP performance in this regard.

FIGURE 2: NET LOAD DURATION CURVES AND HOURLY LOAD SHAPES



Note: Profiles are expressed as a % of profile peak load. All systems are assumed to have 50% renewable penetration. Orange lines show the modeled BA system, and gray lines represent the other 133 applicable balancing areas considered from NREL's Cambium dataset. Negative net load occurs when renewable generation exceeds load in a given hour.

Marginal Hourly Energy Costs

We use 2021 Western Energy Imbalance Market (EIM) hourly real-time locational marginal price data at a price node in the modeled utility region to establish an hourly energy price shape. We then scale this price shape to be consistent with forecasted on- and off-peak energy prices from NREL's Mid-Case 95 by 2035 Cambium Scenario for balancing area 34 in 2030. This approach simultaneously preserves the volatility observed in actual market prices (which model-based forecasts tend to under-represent)[9] while remaining consistent with expected future price trends as the modeled power system continues to decarbonize.

These prices are zonal average energy prices and do not capture local nodal congestion. VPPs could provide additional system benefits not quantified in this study if they are located in congested portions of the grid. We choose to highlight VPP value under "normal" conditions, with the understanding that VPPs would provide additional value in systems with high

[9] Seel, Joachim and Andrew Mills, "Integrating Cambium Marginal Costs into Electric-Sector Decisions," Lawrence Berkeley National Laboratory, November 2021.

congestion. The avoided transmission and distribution benefit captures some congestion relief value.

Emissions

We value changes in CO_2 emissions at the social cost of carbon. In this study, we assume the social cost of carbon is $100/metric ton of CO_2 emitted. Social costs of carbon estimates can vary significantly depending on the assumed social discount rate and approach to modeling the damages of climate change. Our $100/metric ton assumption is within the range of estimates used by industry analysts to evaluate the benefits of decarbonization initiatives.[10] We analyzed the impact of the additional social cost of carbon estimates through sensitivity analysis.

To establish the utility's marginal CO_2 emissions rate, we used hourly marginal CO_2-equivalent emissions rates from NREL's Cambium Mid-Case 95 by 2035 Scenario in 2030. The modeled emissions impact is an average of the impacts quantified with a short-run marginal emissions rate and a long-run marginal emissions rate. The short-run marginal emissions rate is the emission rate of the existing marginal generator on the system. The long-run marginal emissions rate is the expected emissions rate of units that will be added to the system to serve new load growth. Since both are reasonable perspectives and given the medium-term focus of our study, we use the midpoint of the two cost estimates.

Ancillary Services Prices

As a proxy for future ancillary services prices, we used historical MISO day-ahead 10-minute reserve prices for the calendar year 2021, sourced from Velocity Suite.[11] We used historical prices as a proxy for future prices due to uncertainty in forecasting future ancillary services prices. We used spinning reserves rather than frequency regulation because the spinning reserves market is less at risk of saturation from utility-scale batteries. An additional sensitivity case considers zero benefits from the ancillary services market, representing a potential future decline in this market opportunity relative to current prices.

Utility-scale battery storage, gas peaker plants, and the grid-interactive water heater component of the VPP are modeled as providing ancillary services in this analysis. Grid-

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10 There is a wide range of accepted $/ton carbon values. The current official federal estimate of the social cost of carbon is $76/ton in 2020 dollars, assuming a 2.5% discount rate and $51/ton assuming a 3% discount rate. RFF developed an estimate of around $121/ton at a 2% discount rate in analysis in New York, which was adopted by the New York Department of Environmental Conservation (DEC). More recently, RFF staff published a study in Nature estimating the cost to be $185 at a 2% discount rate. California has recently used values between $150/ton and $200/ton. The EPA released a draft estimate of $190/ton at a 2% discount rate.

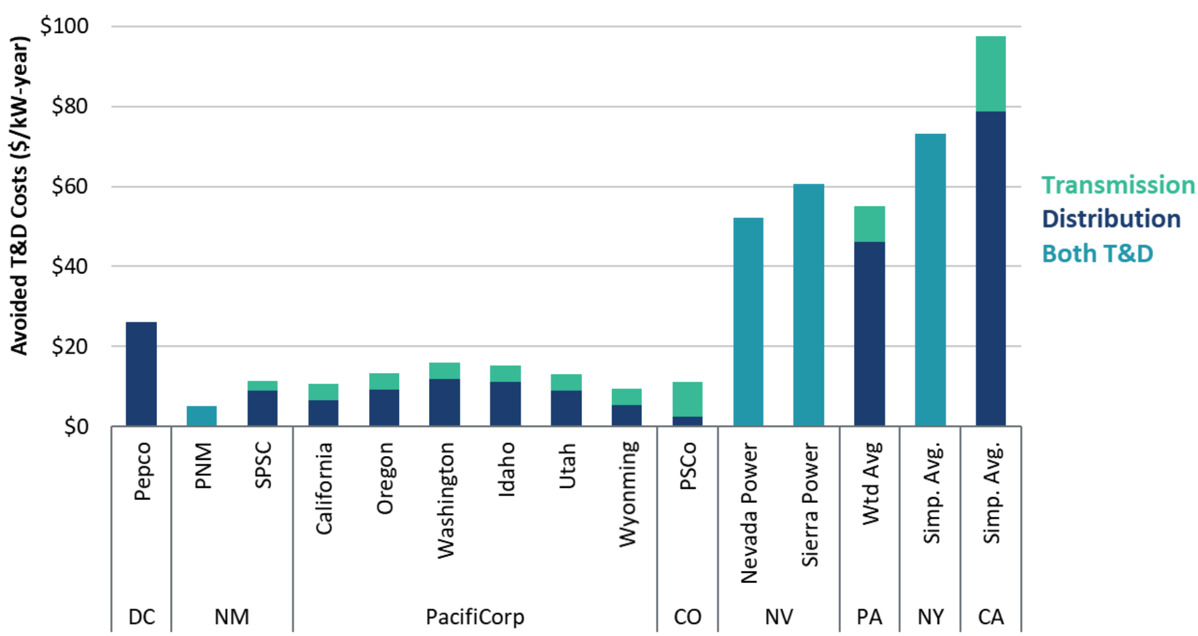
11 Velocity Suite, ABB inc.

interactive water heater program cost assumptions account for the additional technology needed to provide ancillary services.

Avoided Transmission and Distribution (T&D)

Resources located on the demand side can avoid transmission and distribution system upgrades by providing resource adequacy at the load source. Avoided transmission and distribution system costs can vary greatly by utility, and even within a utility service territory. We assume transmission costs of $15/kW-yr and distribution costs of $35/kW-yr based on a review of avoided T&D cost assumptions from other U.S. jurisdictions, see Figure 3. Additional assumptions are considered in sensitivity cases.

FIGURE 3: BRATTLE SURVEY OF AVOIDED T&D COSTS



Resilience

Certain components of VPPs may be able to provide participating customers with resilience benefits. Specifically, when there is a distribution outage, we assume customers with standalone behind-the-meter (BTM) batteries can use those batteries as backup generation. Our analysis does not also consider the potential for electric vehicles to provide backup power to the home or to the grid, as our view is that this capability is still in the emerging stages of technological readiness and commercial availability.

On average, residential customers in the U.S. experience around eight outage hours per year, spread over a couple of outage events. We assume the BTM battery provides 22.5 kWhs of outage relief (capacity of storage) over two events per year, for a total of 50 kWhs per BTM storage participant.[12] This outage is valued at $1,000/MWh based on a conservative value of lost load assumption.[13] Given the relatively small number of BTM battery participants in our assumed VPP configuration, the resilience benefit remains a small portion of the total modeled value of the VPP.

Line Losses

We assume 5% losses for energy flows across transmission and distribution lines.[14]

Study Timeframe

We model future utility system conditions based on public projections for 2030. Specifically, our assumed market penetration of renewable generation, marginal costs, emissions rates, and load profiles reflect conditions that a decarbonizing utility could experience within the next decade. This forward-looking representation of the utility system ensures that our analysis accounts for rapid changes in the power sector that are occurring throughout North America.

Our base case evaluates the performance and economics of the three resource types under those market conditions, assuming current technology costs, so that the findings are not dependent on uncertain projections of future technology decline rates. A sensitivity case captures the impact that future technology cost declines would have on our findings. We assume growth in consumer adoption of VPP technologies through 2030 to account for the expected near-term increase in distributed energy resources (DERs) market penetration, as described in the next section of this report.

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12 EIA, "U.S. Electricity Customers Experienced Eight Hours of Power Interruptions in 2020," November 2021, https://www.eia.gov/todayinenergy/detail.php?id=50316

13 Sullivan, M J, Matthew Mercurio, and Josh Schellenberg, "Estimated Value of Service Reliability for Electric Utility Customers in the United States," 2009; Bauk, Sunhee, Alexander Davis, and Morgan Granger, "Assessing the Cost of Large-Scale Power Outages to Residential Customers," 2018; MISO Market Subcommittee, "Value of Lost Load (VOLL) and Scarcity Pricing," 2020.

14 EIA, "How much electricity is lost in electricity transmission and distribution in the United States?" 2022, https://www.eia.gov/tools/faqs/faq.php?id=105&t=3

III. The Virtual Power Plant

We model the operations and net costs associated with providing 400 MW of resource adequacy from a VPP. While VPPs can be composed of a variety of DERs, for this study we focus on load flexibility from four home energy technologies: smart thermostats, home electric vehicle (EV) managed charging, smart water heating, and BTM battery storage. Our modeled VPP does not include rooftop solar, though that certainly could be a significant element of other VPP configurations.

Eligibility

Customer eligibility for each modeled load flexibility program is limited to the share of customers expected to own a corresponding qualified technology (e.g., an electric vehicle) by 2030. We base technology penetration assumptions on EIA's 2020 Residential Energy Consumption Survey data as well as Brattle technology adoption forecasts. Of the eligible customers, only a portion will participate in the modeled programs.

Participation

We base participation assumptions for each program on an extensive review of regional market potential studies across the U.S. These studies use methods such as primary market research (customer surveys), reviews of achieved participation in successful load flexibility programs, interviews with customer account managers, review of utility DR plans, and expert judgment to establish achievable participation rates for the modeled programs.

Our assumed participation rates are consistent with enrollment in successful utility DR programs across the U.S. In fact, some utilities have achieved participation rates higher than the participation rates modeled in this study. For example, smart thermostat participation has exceeded 50% enrollment among eligible customers in Xcel Energy's A/C direct load control program in Colorado.[15] Our eligibility and participation rate assumptions are summarized in Table 1 below.

[15] Public Service Company of Colorado, "2021/2022 Demand-Side Management Plan" March 2021, https://www.eebco.org/resources/Documents/MEMBERS%20ONLY/XCEL%20ENERGY/Xcel%20Energy%20CO_2021-22_DSM_Plan_Final.pdf

TABLE 1: ASSUMED ELIGIBILITY AND PARTICIPATION RATES

Program	Eligibility (% of residential customer base)	Participation (% of eligible customer base) [16]
Smart thermostat DR	67% summer; 35% winter[17]	30%
Smart water heating	50%[18]	30%
Home EV managed charging	15%[19]	40%
BTM battery DR	1%[20]	20%

Program Operations

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

Per-participant load impacts are based on a review of existing program impact evaluation studies and technology performance characteristics. Program load impacts vary by hour – based on when the event is called and how much customer load is available to curtail. Sources of impact assumptions are described in Table 2.

16 Further documentation on the development of these participation rates is provided in U.S. Department of Energy, Building Technologies Office, "A National Roadmap for Grid-Interactive Efficient Buildings," Figure 8, p. 96, May 2021, https://gebroadmap.lbl.gov/

17 EIA Residential Energy Consumption Survey (RECS) data (2020) tables HC6.6 and HC7.6, United States average. Represents current share of customers with central air-conditioning (summer) or centrally-controlled electric heating (winter).

18 EIA RECS Survey data (2020) tables HC8.6, United States average. Represents current share of customers with electric resistance water heating. Customers need to have grid-connected water heaters to participate in the program. The incremental costs associated with connecting those water heaters to the grid is reflected in program cost assumptions and participation rates.

19 Brattle assumption based on US EV sales and stock forecast.

20 Assumption consistent with BTM stand-alone storage and storage + PV growth forecasts from Lawrence Berkeley National Lab, https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_trends_final.pdf, and EIA, https://www.eia.gov/todayinenergy/detail.php?id=54379

TABLE 2: VPP OPERATIONAL CHARACTERISTICS

Program	Per Participant Peak Impact	Event Frequency	Load Building Assumptions
Smart thermostat DR	1 kW summer; 0.5 kW winter[21]	15 five-hour events per season, plus 100 hours of minor set point adjustments per year	40% of reduced load (2 hours of pre-heating/cooling and 4-hour post-event snapback period)
Smart water heating	Customer impact varies by hour, based on water heating load available to curtail (0.27–0.51 kW)[22]	Daily shifting of water heating load	100% of reduced load
Home EV managed charging	Customer impact varies by hour, based on average LDV fleet charging load available to curtail. 80% of EV charging load can be reduced (0.21–0.75 kW, dependent on hour of event)[23]	Daily shifting of vehicle charging load	100% of reduced load
BTM battery DR	7.5 kW per customer[24]	15 events per year, 3 hours per event	100% of reduced load

21 Impacts based on Brattle review of third-party reports analyzing Nest Thermostat DR operations: CenterPoint, Cadmus (2022); Indianapolis Power & Light, Cadmus (2020); KCP&L, Navigant (2017)

22 Water heating load reduction potential based on customer data from DOE TMY2 Residential Data provided by Open EI, https://openei.org/datasets/files/961/pub/EPLUS_TMY2_RESIDENTIAL_BASE/. 10% of maximum water heating load can be curtailed in any hour.

23 Vehicle charging load reduction potential is based on EV charging profiles sourced from the U.S Department of Energy's EVI Pro Lite tool, https://afdc.energy.gov/evi-pro-lite. These charging profiles represent, in a given hour, the average per-vehicle at-home charging demand for the entire electric LDV fleet. Not all EVs charge in all hours, and at a given time, some portion of the EVs will not be plugged in. A maximum of 80% of this average charging load can be reduced in any hour. Depending on what hour of the day an event is called, the range of potential EV charging load that can be curtailed is 0.21kW to 0.75kW.

24 BTM battery parameters are assumed to have a 3-hour duration, 5 kW max continuous output, and 15 kWh capacity. We assume an average of 1.5 batteries per participant. On average, in the U.S., residential customers have between one and two batteries. These storage parameters are roughly consistent with current models in market, for example, the Tesla Powerwall. Each participant has 7.5 kW available to dispatch fully in event hours and 22.5 kWh of capacity. During the 15 events called each year, participants are assumed to have enough advanced notice to charge such that assets could fully dispatch during event programs. Fifteen events per year is a conservative estimate based on limits in existing program designs and accounts for the potential for participant event overrides.

Costs

We developed VPP program costs from a review of utility DR potential studies, existing program costs, and pilot programs in U.S. jurisdictions.[25] Program costs considered in this study represent costs incurred by the utility to attract participants and operate each program. We take a utility perspective on costs because our analysis focuses specifically on the cost to utilities of achieving a desired level of resource adequacy. This is similar to the perspective taken in integrated resource planning, which informs utility investment decisions.

One-time costs are annualized based on a 10-year economic lifetime of participation in each program and an 8% nominal discount rate. We exclude program setup costs because we assume the utility has existing DR infrastructure in place. Incremental distributed energy resource management systems (DERMS) costs are included on a per-participant basis in the total non-incentive costs column of Table 3 below. The sum of the highlighted two right-most columns (non-incentive costs and annual incentive) represents the total levelized annual per-participant costs for each program.

25 Cadmus, BPA DR Potential (2018); GDS, BWL DSM potential (2020); Applied Energy Group, PacifiCorp Potential (2021); Lawrence Berkeley National Lab, DR Cost Assessment (2017); Navigant Arkansas Energy Efficiency Potential Study (2015)

TABLE 3: MODELED VPP COSTS ($2022)

Program	Variable equipment and installation cost	Annual program administration[26]	Marketing and recruitment[27]	Total non-incentive costs	Annual incentive
	$/part	$/yr	$/part	**$/part-yr**	**$/part-yr**
Smart thermostat DR	$75 (up-front enrollment incentive or thermostat rebate)	$30,000	$50	**$43**	**$25 per season**
Smart water heating	$315 (incremental equipment cost to enable grid interactivity)	$30,000	$50	**$55**	**$30**
Home EV managed charging	$0	$30,000	$50	**$80**	**$100**
BTM battery DR	$0	$30,000	$50	**$140**	**$500**

IV. Natural Gas Peaker

We model a natural gas peaker's net cost of serving 400 MW of resource adequacy. We simulate hourly dispatch of the peaker using a production cost model that optimizes unit commitment and dispatch based on hourly energy prices, ancillary prices, and variable costs. See below for additional detail on dispatch modeling.

[26] Assumes one full-time employee dedicated to running the VPP program with an annual salary of $120,000/yr.

[27] Per-participant marketing costs are developed based on a review of existing programs and utility demand response potential reports. Costs include Cadmus, BPA DR Potential (2018); GDS, BWL DSM potential (2020); Applied Energy Group, PacifiCorp Potential (2021).

Plant Capacity

We model 440 MW of peaker capacity to serve 400 MW of resource adequacy, assuming a 10% equivalent forced outage rate.[28] In more extreme conditions – as has recently occurred in PJM, among other markets – total outage rates have approached values closer to 20%, which would require an even greater level of investment in gas peaking capacity to provide the same overall level of resource adequacy.[29]

Natural Gas Fuel Prices

We rely on the annual Henry Hub spot price ($3.76/MMBtu),[30] from the EIA's Annual Energy Outlook, to be consistent with the gas price assumptions used in the modeling behind NREL's Cambium dataset. We then shape the annual price based on 2021 monthly historical spot prices from Cheyenne Hub[31] sourced from S&P Global Market Intelligence. This maintains consistency with the energy prices used in our analysis while also capturing seasonal gas price variation.

Gas Peaker Specifications

We assume the peaker is a natural gas burning combustion turbine with a heat rate of 8.873 MMBtu/MWh, based on current GE Gas Power models.[32]

Cost Assumptions

We assume a capital cost of $985/kW, levelized over 20 years at an 8% nominal discount rate, to get an annual capital cost of $100.40/kW-yr. We assume fixed operations and maintenance (O&M) costs of $24.05/kW-yr. We model a variable O&M cost of $5.20/MWh. We source all cost inputs from the NREL 2022 Annual Technology Baseline (ATB) for a 2022 online date, representing current plant technology costs in $2022.[33]

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[28] North American Electric Reliability Corporation (NERC), Generating Unit Statistical Brochures, Brochure, 2021 – All Units Reporting, August 1, 2022, https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx

[29] PJM, System Operations Report, May 12, 2022, https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20220512/item-02---review-of-operating-metrics.ashx and Howland, Ethan, "PJM generators face up to $2B in penalties for failing to run during December's Winter Storm Elliot," January 12, 2023, https://www.utilitydive.com/news/pjm-generators-penalties-power-winter-storm-elliott/640242/

[30] U.S. Energy Information Administration (EIA), Annual Energy Outlook 2022, Table 13.

[31] S&P Global Market Intelligence as of 12/15/2022.

[32] GE 7F.04 turbine model, https://www.ge.com/gas-power/products/gas-turbines/7f

[33] National Renewable Energy Labs (NREL), 2022 Annual Technology Baseline (ATB), https://atb.nrel.gov/electricity/2022/index. These costs are benchmarked against public and industry values such as the EIA AEO 2022, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf

Emissions Cost

We calculate gas peaker net carbon impact based on the emissions content of natural gas combustion and any marginal emissions displaced with hourly gas peaker generation. We assume natural gas has a carbon content of 53 kg/MMBtu.[34] Emissions costs are valued at a social cost of carbon of $100/metric ton in the base case, as described above.

V. Utility-Scale Battery Storage

We model a transmission-connected utility-scale battery storage resource's net costs associated with providing 400 MW of resource adequacy. Battery dispatch is simulated using Brattle's bStore model[35] and optimized relative to forecasted energy and ancillary services prices. We account for the revenue potential associated with co-optimized battery dispatch into day-ahead and real-time energy markets with a 28% revenue adder, which we developed from prior analysis of historical real-time and day-ahead market participation of batteries in several jurisdictions across the United States.

Plant Capacity

We model 400 MW of lithium-ion battery storage comprised of a 175 MW battery with 4-hour duration (i.e., 700 MWh) and 225 MW of 6-hour duration (i.e., 1,350 MWh). We determined the capacity and duration split based on analysis of the modeled utility system's net load and related resource adequacy performance needs.

In order to fully provide 400 MW of resource adequacy, there are certain net peak demand days that require 400 MW of dispatch in more than four hours of the day, thus necessitating additional energy storage capacity and a longer-duration battery. We include an additional sensitivity case that examines the net costs of a 400 MW battery composed of only 4-hour duration storage, even though this battery would not fully provide 400 MW of resource

[34] Environmental Protection Agency, "Emission Factors for Greenhouse Gas Inventories," https://www.epa.gov/sites/default/files/2015-07/documents/emission-factors_2014.pdf and Greenhouse Gas Protocol, "Global Warming, Potential Values," https://www.ghgprotocol.org/sites/default/files/ghgp/Global-Warming-Potential-Values%20%28Feb%2016%202016%29_1.pdf

[35] *See* The Brattle Group, bSTORE, https://www.brattle.com/practices/electricity-wholesale-markets-planning/electricity-market-modeling/bstore/

adequacy as we have defined it in this study. We assume both asset types have 85% round trip efficiency from the NREL Annual Technology Baseline.[36]

Cost Assumptions

We use capacity cost assumptions from the NREL 2022 ATB for assets with a 2022 online date, representing current battery storage costs.[37] We expect battery storage costs to decline in the future with technological development and large-scale deployment. We model current costs in the base case and include a sensitivity with forecasted 2030 costs to account for the uncertainty around storage costs. Current costs are $1,018/kW for a 4-hour battery and $1,437/kW for a 6-hour battery. We levelize the costs at an 8% nominal discount rate over 15 years to arrive at annual costs of $118.97/kW-yr (4-hr) and $167.93/kW-yr (6-hr). We also apply a 30% capital cost reduction based on the Investment Tax Credit (ITC). Fixed O&M costs are $36.37/kW-yr (4-hr) and $51.33/kW-yr (6-hr), also from the NREL ATB.

VI. Sensitivity Analysis Assumptions

We model several additional cases to determine the sensitivity of our findings to changes in assumptions about market conditions and technology costs. The base case serves as a central representation of future market conditions. Each sensitivity explores alternative individual modeling assumptions.

Higher Carbon Price

We value carbon impacts at $190/metric ton instead of $100/metric ton, based on the EPA's draft value.[38] This sensitivity case represents a scenario in which decision-makers place a higher cost on carbon emissions and, therefore, a higher value on measures that can reduce emissions.

Lower Carbon Price

We assume a carbon price of $50/metric ton, half of the base case carbon cost and generally consistent with the current official federal estimate using a 3% discount rate.

[36] National Renewable Energy Labs (NREL), 2022 Annual Technology Baseline, https://atb.nrel.gov/electricity/2022/index

[37] Ibid.

[38] Environmental Protection Agency, "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances," September 2022, https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf

Higher T&D Cost

We assume $25/kW-yr for avoided transmission and $50/kW-yr for avoided distribution (compared to $15/kW-yr for transmission and $35/kW-yr for distribution in the base case). Avoided transmission and distribution costs can vary greatly across utility systems and even within a given utility system. This sensitivity is applicable to markets with higher transmission and distribution system costs or cases where the VPP is deployed specifically to defer or avoid T&D capacity upgrades with higher-than-average costs.

Lower T&D Cost

We assume $5/kW-yr for transmission and $10/kW-yr for distribution. This sensitivity accounts for some markets that will not realize significant T&D investment deferral value from VPPs.

2030 Technology Cost Trends

We account for uncertainty in the future cost of the three resource types. Specifically, we assume that the installed cost of these resources will decline between now and 2030 due to technological advancement. We assume VPPs will have 30% lower DERMS costs than in the base case as DERMS developers achieve scale. Utility-scale battery storage and gas peaker cost declines are consistent with NREL's ATB moderate forecast in 2030. Gas peaker costs are 10% lower than the base case, and storage assets are 35% lower. We also assume utility-scale storage earns a reduced ITC of 15% due to uncertainty regarding the extent to which the current ITC level will persist in a future scenario that already includes significant fundamental storage cost declines.

Business-as-Usual (BAU) Renewables Deployment

We assume the modeled utility only reaches 15% renewable saturation, compared to 50% in the base case. This 15% saturation is close to the average market penetration of renewable generation in the United States currently. We use NREL's Cambium Mid-Case scenario for related assumptions such as hourly renewable generation shape and marginal energy costs, as opposed to the Mid-Case 95 by 2035 Scenario, which we used in the base case. In this scenario, resource adequacy needs to target different net peak hours due to the adjusted net load profile. The configuration and assumed capacity of all three resource types are sufficient to provide 400 MW of resource adequacy in both the business-as-usual renewables case and the base case.

Energy Value Only

We assume no benefits related to the provision of ancillary services. We adjust asset hourly dispatch decisions to consider only energy market opportunities. This sensitivity represents a market with low or uncertain ancillary services prices due to significant competition from a large deployment of utility-scale battery storage, for example.

Alternative Battery Configuration

We assume only 4-hour duration utility-scale battery storage is deployed, with no 6-hour duration storage. This scenario cannot fully meet the performance requirements needed to provide 400 MW of resource adequacy as we have defined it in this study. However, we include this sensitivity given that current utility-scale battery deployments commonly focus on 4-hour duration batteries.

VII. Detailed Results of Analysis Cases

The resulting costs, benefits, and net costs of each resource configuration in each sensitivity case are shown in Table 4. In the table, we present costs as positive values since this study focuses on estimating the net cost of resource adequacy. As such, a negative "system cost impact" or "societal cost impact" represents cost savings attributed to the resource. In other words, negative values represent a benefit to the system. For example, a VPP has a negative societal cost impact for "emissions" because the VPP reduces the societal cost of greenhouse gas (GHG) emissions.

In the table, the "net cost (system)" metric represents the net cost of resource adequacy to the utility and focuses only on resource costs incurred or saved by the utility. It is calculated by adding the system cost impacts to the resource costs (CapEx, fuel, O&M, program costs). The "net cost (societal)" metric additionally includes the societal cost impacts of the three resource types when calculating the net cost of resource adequacy.

The results illustrate the impacts of a range of assumptions about market conditions and technology costs on our findings regarding the net cost of providing resource adequacy from the three analyzed resource types. Across all of the sensitivities cases, the VPP is the only option with the potential to provide resource adequacy value at a negative net cost to net society. In other words, the additional (non-resource adequacy) value provided by VPPs can be higher than its costs *before* accounting for its core resource adequacy benefit. The economic competitiveness of VPPs and battery storage in particular will vary from one market to the next and will depend on the trajectory of future cost declines.

TABLE 4: ANNUAL COSTS, BENEFITS, AND NET COSTS ACROSS ALL MODELED SCENARIOS (2022$MILLION/YR)

		Base Case	Higher Carbon Price	Lower Carbon Price	Higher T&D Cost	Lower T&D Cost	2030 Tech Cost Trend	Energy Only	BAU Renewables Deployment	4-hr Storage
Gas Peaker	*System Cost Impact*									
	Energy	-$26.06	-$26.06	-$26.06	-$26.06	-$26.06	-$26.06	-$26.93	-$28.93	-$26.06
	Ancillary Services	-$1.58	-$1.58	-$1.58	-$1.58	-$1.58	-$1.58	$0.00	-$1.53	-$1.58
	T&D Investment Deferral	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Societal Cost Impact									
	Emissions	$1.90	$3.62	$0.95	$1.90	$1.90	$1.90	$1.90	$4.43	$1.90
	Resilience	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total System Cost Impact	-$27.63	-$27.63	-$27.63	-$27.63	-$27.63	-$27.63	-$26.93	-$30.46	-$27.63
	Total Societal Cost Impact	-$25.73	-$24.02	-$26.68	-$25.73	-$25.73	-$25.73	-$25.02	-$26.03	-$25.73
	Resource Cost	$69.04	$69.04	$69.04	$69.04	$69.04	$65.30	$68.54	$70.53	$69.04
	Net Resource Adequacy Cost (System)	$41.40	$41.40	$41.40	$41.40	$41.40	$37.67	$41.61	$40.07	$41.40
	Net Resource Adequacy Cost (Societal)	$43.30	$45.02	$42.35	$43.30	$43.30	$39.57	$43.52	$44.51	$43.30
Utility-Scale	*System Cost Impact*									
Battery	Energy	-$32.04	-$32.04	-$32.04	-$32.04	-$32.04	-$32.04	-$32.96	-$32.71	-$30.00
	Ancillary Services	-$15.51	-$15.51	-$15.51	-$15.51	-$15.51	-$15.51	$0.00	-$15.54	-$15.91
	T&D Investment Deferral	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Societal Cost Impact									
	Emissions	$1.14	$2.17	$0.57	$1.14	$1.14	$1.14	$1.54	$2.72	$1.17
	Resilience	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total System Cost Impact	-$47.55	-$47.55	-$47.55	-$47.55	-$47.55	-$47.55	-$32.96	-$48.25	-$45.91
	Total Societal Cost Impact	-$46.40	-$45.37	-$46.98	-$46.40	-$46.40	-$46.40	-$31.42	-$45.54	-$44.74
	Resource Cost	$75.02	$75.02	$75.02	$75.02	$75.02	$55.45	$75.02	$75.02	$60.92
	Net Resource Adequacy Cost (System)	$27.47	$27.47	$27.47	$27.47	$27.47	$7.90	$42.06	$26.76	$15.01
	Net Resource Adequacy Cost (Societal)	$28.61	$29.64	$28.04	$28.61	$28.61	$9.05	$43.60	$29.48	$16.18
VPP	*System Cost Impact*									
	Energy	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$9.45	-$10.46	-$9.45
	Ancillary Services	-$0.75	-$0.75	-$0.75	-$0.75	-$0.75	-$0.75	$0.00	-$0.75	-$0.75
	T&D Investment Deferral	-$21.00	-$21.00	-$21.00	-$31.50	-$10.50	-$21.00	-$21.00	-$21.00	-$21.00
	Societal Cost Impact									
	Emissions	-$14.76	-$28.04	-$7.38	-$14.76	-$14.76	-$14.76	-$14.76	-$13.41	-$14.76
	Resilience	-$0.16	-$0.16	-$0.16	-$0.16	-$0.16	-$0.16	-$0.16	-$0.16	-$0.16
	Total System Cost Impact	-$31.21	-$31.21	-$31.21	-$41.71	-$20.71	-$31.21	-$30.45	-$32.21	-$31.21
	Total Societal Cost Impact	-$46.12	-$59.41	-$38.74	-$56.62	-$35.62	-$46.12	-$45.37	-$45.78	-$46.12
	Resource Cost	$48.34	$48.34	$48.34	$48.34	$48.34	$45.09	$48.34	$47.67	$48.34
	Net Resource Adequacy Cost (System)	$17.14	$17.14	$17.14	$6.64	$27.64	$13.88	$17.89	$15.46	$17.14
	Net Resource Adequacy Cost (Societal)	$2.22	-$11.07	$9.60	-$8.28	$12.72	-$1.04	$2.97	$1.89	$2.22

Note: Costs are presented as positive values in the table. "Resource Cost" includes Capex, fuel, O&M for the gas peaker and battery, and it includes all utility-incurred costs (participation incentives software, administration, marketing) for the VPP."Net Resource Adequacy Cost (Societal)" accounts for both "system" and "societal" cost impacts.

VIII. The Load*Flex* Model

The Brattle Group's Load*Flex* model was developed to quantify the potential impacts, costs, and benefits of demand response and load flexibility programs. The Load*Flex* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging "DR 2.0" programs, which not only reduce system peak demand but also provide around-the-clock load management opportunities.

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

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospitals or universities). Load curtailment capability is further calibrated to the utility's experience with DR programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), LoadFlex includes an hourly profile of load interruption capability for each program. For instance, for a home EV charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.
- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose.

LoadFlex accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

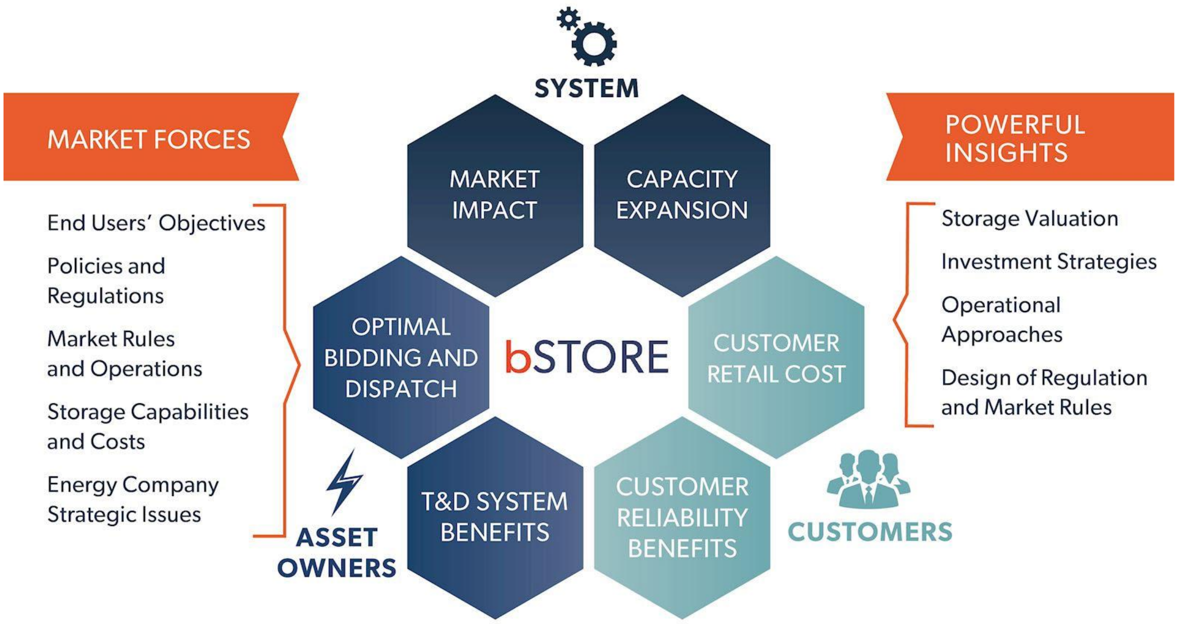
- **Industry-validated program costs:** DR program costs are based on a detailed review of the utility's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

IX. The bStore Model

The bStore modeling suite is a storage simulation and decision-support platform used to assess the value of storage projects. bSTORE provides insights into key aspects of the value of storage, including:

- Co-optimization across energy and ancillary service products
- Redispatch between day-ahead and 5-minute real-time markets
- Realistic foresight of future prices when dispatching into day-ahead (DA) and real-time (RT) markets
- Cycling limitations and degradation costs

FIGURE 4: OVERVIEW OF THE BSTORE MODELING PLATFORM



bStore is highly configurable to account for the specific characteristics of the asset being analyzed as well as the underlying market rules for the RTO in which the asset is operating. Key input parameters to bStore include:

- Battery capacity (MW and MWh)
- Round-trip efficiency
- Degradation characteristics, including cycling limitations, augmentation costs, anticipated reduction in MWh over time, and warranty/long-term service agreement (LTSA) parameters
- Min/max state of charge
- Market services capable of being provided
- Any other restrictions on operations
- Anticipated foresight of future prices
- If co-located with solar:
  - Sizing of on-site solar (AC and DC MW)
  - Solar configuration (fixed or single-axis tracking)
  - Solar/storage coupling (AC or DC)

– Injection limit of combined system (MW)

The outputs of bStore include hourly charge/discharge and operations, revenues earned in total and across each market product, and high-level operational statistics such as cycle count and degradation.

X. DER Adoption Estimates

The Volume I report for this study identifies the current and forecasted adoption of several DERs in 2030. In this section, we describe the sources of that data.

Homes with Smart Thermostats

- **Current:** 10% of U.S. homes, based on research by Parks Associates.[39]

- **2030:** Assumes 17.2% compound annual growth rate (CAGR) in U.S. smart thermostat market, based on research by Fortune Business Insights.[40] Assumes 124 million U.S. households today, growing at 0.5% per year (consistent with the recent U.S. population growth rate).

Homes with Electric Water Heating

- **Current:** 49%, based on 60.4 million U.S. homes with some type of electric water heating, according to data behind the U.S Energy Information Administration's 2022 Annual Energy Outlook. Assumes 124 million U.S. households today.[41]

- **2030:** 50%, based on 64.0 million U.S. homes with some type of electric water heating in 2030, according to data behind the U.S Energy Information Administration's 2022 Annual Energy Outlook. Assumes 129 million U.S. households in 2030.[42]

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39 Parks Associates press release found that 13% of homes with internet have smart thermostats; *see* "Park Associates: 27% of smart thermostat owners report owning a Nest thermostat," PR Newswire, October 26, 2022, https://www.prnewswire.com/news-releases/parks-associates-27-of-smart-thermostat-owners-report-owning-a-nest-thermostat-301659852.html. 77% of U.S. homes have internet according to Pew Research; *see* Internet/Broadband Fact Sheet, Pew Research Center, April 7, 2021, https://www.pewresearch.org/internet/fact-sheet/internet-broadband/

40 Fortune Business Insights, U.S. Smart Thermostat Market, February 2023, https://www.fortunebusinessinsights.com/amp/u-s-smart-thermostat-market-106393

41 U.S. EIA, Annual Energy Outlook 2023, March 16, 2023, https://www.eia.gov/outlooks/aeo/

42 Ibid.

Residential Rooftop Solar

- **Current:** 27.4 GW of U.S residential rooftop solar capacity, according to SEIA.[43]

- **2030:** 83 GW of U.S. residential rooftop solar capacity, based on annual additions forecasted by Wood Mackenzie through 2026 and extrapolated to 2030.[44]

Behind-the-Meter Batteries

- **Current:** 2 GW of U.S. BTM battery storage, based on 1 GW deployed in 2020 according to LBNL[45] and assuming 0.6 GW of additions per year in 2021 and 2022, according to data from Wood Mackenzie.[46]

- **2030:** 27 GW, assuming average annual growth of 2.2 GW for residential and 0.9 GW for non-residential between 2022 and 2030. Based on Wood Mackenzie's estimate of the annual rate of adoption in 2026, the midpoint of our forecast horizon.[47]

Light-Duty Electric Vehicles

- **Current:** 3 million, according to the Edison Electric Institute (EEI).[48]

- **2030:** 26 million, according to a forecast by EEI.[49]

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[43] Solar Energy Industries Association (SEIA), Solar Industry Research Data, https://www.seia.org/solar-industry-research-data

[44] Wood Mackenzie, US Solar Market Insight: 2022 Year in Review, https://www.woodmac.com/industry/power-and-renewables/us-solar-market-insight/

[45] Barbose, Galen, Salma Elmallah, and Will Gorman, "Behind-the-Meter Solar+Storage: Market data and trends," Lawrence Berkeley National Laboratory (LBNL), July 2021, https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_trends_final.pdf.

[46] Wood Mackenzie, U.S. Energy Storage Monitor, https://www.woodmac.com/industry/power-and-renewables/us-energy-storage-monitor/

[47] Ibid.

[48] EEI, EV Trends and Key Issues, https://www.eei.org/en/issues-and-policy/electric-transportation#:~:text=Today%20there%20are%20more%20than,2022%20as%20high%20as%208%25

[49] EEI, EEI Projects 26.4 Million Electric Vehicles Will Be on U.S. Roads in 2030, June 20, 2022 https://www.eei.org/News/news/All/eei-projects-26-million-electric-vehicles-will-be-on-us-roads-in-2030