The National Case for a More Distributed Power Grid

New Evidence on Affordability and Demand Growth

VOLUME 1: SUMMARY REPORT

PREPARED BY

Ryan Hledik
Kate Peters
Sophie Edelman
Prisha Tiwari
Carly McAdam
Akhilesh Ramakrishnan

PREPARED FOR

The Pew Charitable Trusts

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Brattle

Pew

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See the accompanying Volume II: Technical Appendix of this report for additional detail on methodology and data sources.



At a Glance

New approaches are needed to serve the next era of growth.

Rapid demand growth is colliding with rising infrastructure costs, long resource-development timelines, affordability pressures, and the continued need to decarbonize the power system. Distributed energy resources (DERs) can help address these challenges by making better use of technologies already adopted by homes and businesses, relieving capacity constraints, producing energy closer to where it is consumed, providing the flexibility needed for a cleaner power system, and compensating customers directly for delivering those services.

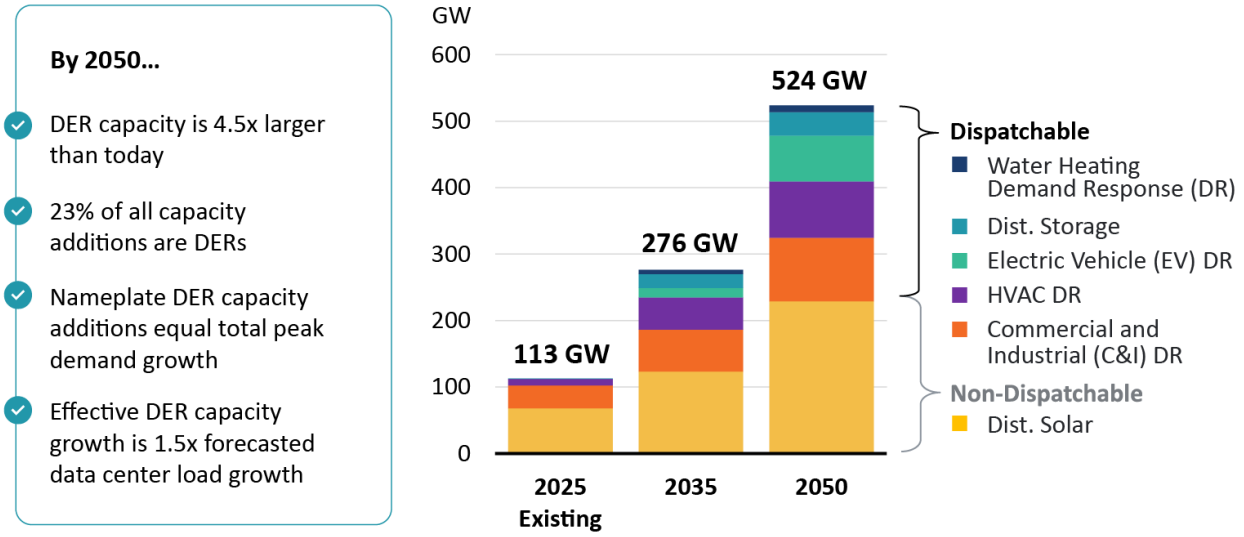
This study evaluates how ambitious but feasible deployment of DERs could benefit the US power grid and customers. Specifically, we consider a scenario in which DER deployment expands nationwide to levels already observed or projected in leading US markets.

We assess impacts on both the bulk power and distribution systems, with particular attention to affordability and broader customer access to those benefits. The modeled portfolio includes non-emitting DERs across residential, commercial, and industrial customers, including flexible HVAC and water heating, managed and bidirectional EV charging, commercial and industrial demand response, and behind-the-meter (BTM) and front-of-meter (FTM) distributed solar and batteries.

DER nameplate capacity could grow from 8% of US installed capacity today to 18% by 2050.

This growth would make DERs the fourth-largest resource in the US capacity mix, adding about 400 GW – roughly equal to total projected load growth over the study horizon. New policy interventions, market design decisions, regulatory initiatives, business models, planning practices, technological innovations, and advancements in consumer engagement could all play a role in unlocking deployment at this scale.

FIGURE ES-1: US DER INSTALLED CAPACITY (NAMEPLATE)



Note: Growth drivers include rooftop solar on one in six single-family homes; 15%–45% customer participation in flexible load offerings, depending on the offering; distributed resources accounting for 21% of all storage additions; and additional front-of-meter solar and commercial and industrial (C&I) flexibility.

Expanded DERs would reduce reliance on new gas generation and shift flexibility to the grid edge.

The modeled portfolio avoids roughly 70 GW, or 22%, of projected net gas additions and shifts about 105 GW of utility-scale storage to the grid edge through distributed storage and other forms of flexibility. By complementing renewable output and reducing curtailment, DERs also support a 3% increase in wind and solar generation over the study period. In addition, when deployed in constrained locations and integrated into utility operations, DERs can defer a meaningful share of load-driven distribution investment.

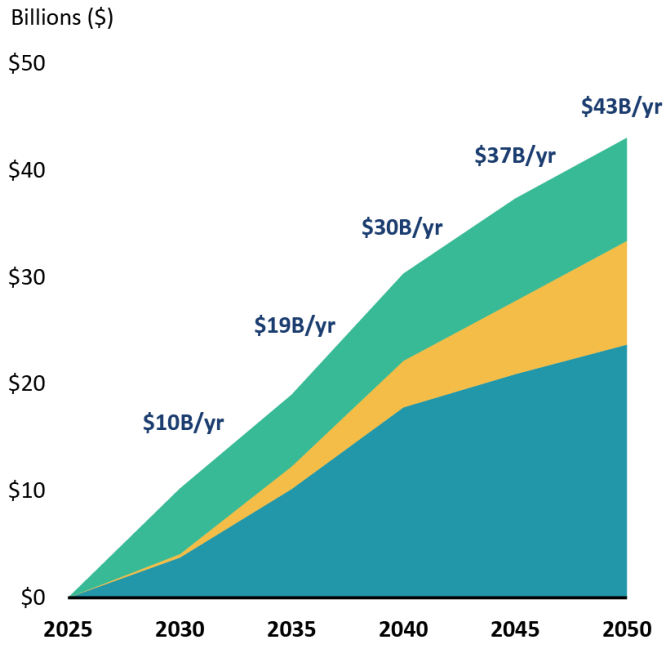
Expanded DER deployment could avoid more than $600 billion in power system costs through 2050 (inflation-adjusted and undiscounted).[1]

Relative to a status quo outlook, roughly half of the cumulative value comes from avoided generation investment and operating costs, and another one-third comes from deferring growth-driven distribution upgrades. Policies to streamline permitting and interconnection add further value by reducing the cost of distributed solar, thereby enabling more financially sustainable compensation frameworks that benefit all customers.

[1] Throughout this report, financial values are reported in 2026 dollars unless otherwise noted.



FIGURE ES-2: ANNUAL US ELECTRIC SYSTEM AVOIDED RESOURCE COSTS



Reduced Distribution System Investment

Cumulative savings: $182B (30% of total)

When DERs are integrated into distribution planning and operated in coordination with grid needs, they can slow the rate of grid capacity expansion.

Distributed Solar Cost Reductions

Cumulative savings: $97B (16% of total)

Improved permitting and interconnection policies decrease costs to deploy distributed solar, which can be shared with all ratepayers by enabling financially sustainable solar compensation frameworks.

Reduced Generation Costs

Cumulative savings: $334B (55% of total)

DERs displace a portion of investments in utility-scale generation by providing flexibility and energy.

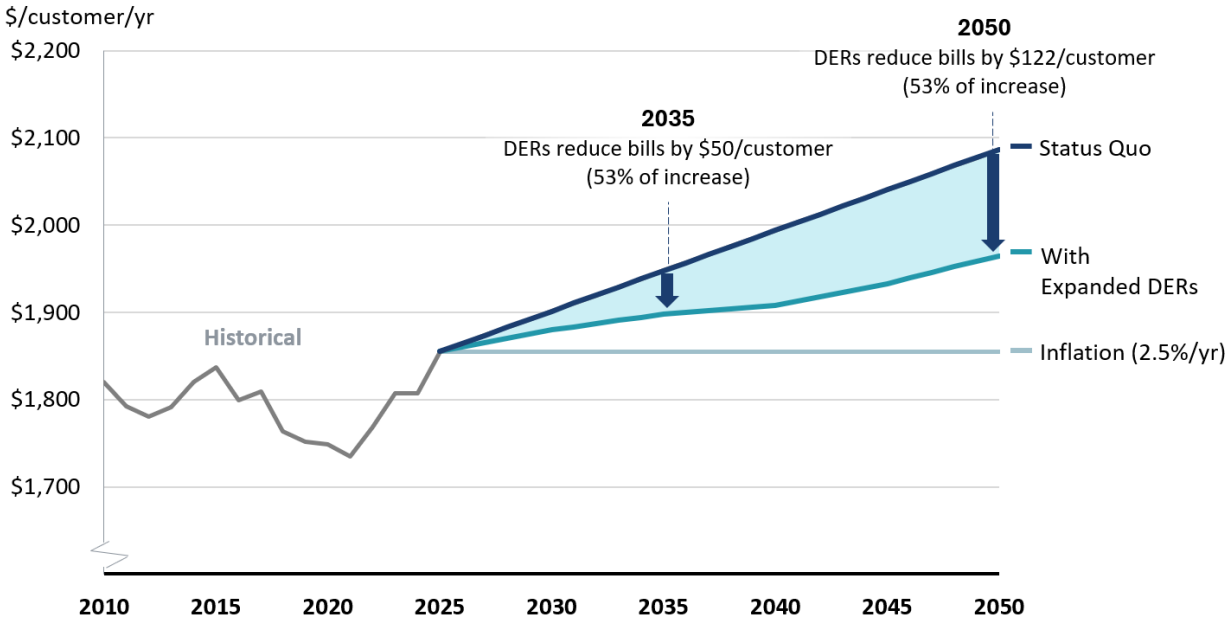
$614 billion
in cumulative avoided resource costs over 25 years (inflation adjusted and undiscounted)

DER cost savings would meaningfully reduce projected household electricity bill increases.

After accounting for the costs of enabling DER deployment, the expanded portfolio offsets roughly half of projected household electricity bill increases beyond inflation by 2035 and saves households an estimated $122 per year by 2050 (in inflation-adjusted terms). DERs alone are not a complete solution to affordability pressures, but they could contribute significantly to returning bill growth to its historically sustainable inflation-aligned trajectory.

The available value is large enough to benefit all customers, though policy and program design will determine how the savings are divided between customers with DERs and those without. After accounting for implementation costs, roughly 80% of the total value is available for allocation among performance compensation for participating customers, downward rate pressure for all customers, and potential incentives for utilities to enable DER solutions.

FIGURE ES-3: US AVERAGE ANNUAL RESIDENTIAL ELECTRICITY BILLS (INFLATION-ADJUSTED 2026 DOLLARS)



Notes: The status quo rate growth trajectory is based on an assumed 0.5% average annual real growth in residential electricity rates across the full study horizon, consistent with projections in the EIA's *Annual Energy Outlook*. For comparison purposes, this assumes no change in annual residential electricity consumption. Changes in electricity consumption would alter the average bill trajectory, but that is separate from the affordability impact analyzed here.

The planning flexibility of DERs could reduce the potential cost of overbuilding the power system to meet uncertain data center demand by 40%.

Uncertain data center demand creates a risk that utilities will build long-lived infrastructure for load that does not materialize. Because DERs have short development timelines and can be deployed at a modular scale, planners can add capacity in measured steps and adjust future procurement – or compensation for existing DERs – as demand becomes clearer. This flexibility would reduce modeled overbuild costs by $33 billion over the decade following a lower-than-expected load outcome.

DERs could reduce emissions and improve the affordability of decarbonizing the power sector.

In the absence of new policy interventions or technological breakthroughs, our analysis indicates that reductions in US power sector carbon dioxide emissions will stall around 2035. By facilitating the integration of additional renewable generation into the power system, an expanded portfolio of DERs could help sustain the current decarbonization momentum, driving a 3% cumulative reduction in carbon dioxide emissions over the study period.

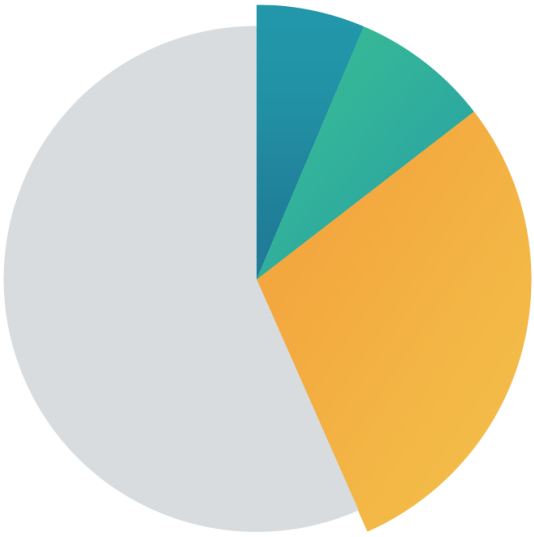
Separately, in a scenario targeting a carbon-free power sector by 2050, DER flexibility could avoid the need for roughly 175 GW of cumulative large-scale capacity, lowering the incremental cost of achieving decarbonization by 20% ($45 billion) in 2050. DERs can also support broader economy-wide emissions

reductions by enabling beneficial electrification – for example, by mitigating new load impacts and reducing associated infrastructure needs.

Three practical policy initiatives could unlock over 40% of the identified DER benefits.

Given the breadth of the pathways available for addressing barriers to DER deployment and enabling the level of adoption assumed in this study, and likely variation in their relative attractiveness across jurisdictions, this study did not assume or prescribe specific approaches taken to unlock DER benefits. However, to provide a tangible illustration of the potential impact of targeted action, we examined three specific reforms recently identified by Pew as priorities[2]: integrating DERs into distribution planning and operations, streamlining permitting, and reforming interconnection to enable flexible exports. Together, those initiatives could account for an estimated 43% of cumulative national benefits. These reforms are not a complete policy agenda, but they are high-impact near-term steps toward enabling DERs to compete as a core grid resource.

FIGURE ES-4: CONTRIBUTION OF THREE POLICY INITIATIVES TO NATIONAL DER BENEFITS



Interconnection Reform | $39B, 6% of total

- Would accelerate connections while giving utilities tools to manage constraints
- Flexible interconnection agreements and "dynamic operating envelopes" can allow DERs to export within limits that reflect local grid conditions

Permitting Reform | $50B, 9% of total

- Behind-the-meter (BTM) solar & storage permitting is fragmented, duplicative, and costly
- Streamlining the process could reduce permitting costs by 90% (achieved in Australia and Germany)

Distribution System Value | $177B, 29% of total

- Utilities must be able to forecast their availability, communicate dispatch needs, verify performance, and compensate for dependable local capacity
- Requires DER deployment where constraints are expected, aggregated at sufficient scale, and incorporated into utility planning, procurement, and operations

Other Reforms | $347B, 57% of total

Additional progress needed to modernize utility regulation, develop more effective approaches to consumer engagement, and create clearer, more consistent pathways for DERs to capture the full value they provide (among others)

The United States will need a broad portfolio of resources to meet growing electricity demand while maintaining affordability, reliability, and progress toward decarbonization. DERs are one component of this broader portfolio and will complement continued investment in conventional infrastructure, energy efficiency, and other solutions. By planning for and deploying DERs at scale, decision-makers can unlock a lower-cost, more flexible system that responds quickly to changing needs while delivering benefits to households and businesses.

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[2] See The Pew Charitable Trusts, *Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future*, April 2026.

Section 1: Introduction

An Emerging Solution for New Challenges

For most of its history, the US power sector has met growing demand primarily by building more large-scale, centralized infrastructure. The past decade required roughly $2 trillion in capital investment in power plants, transmission system equipment, and distribution system upgrades.[3] That buildout was achievable, in part, because both electricity demand and the cost of serving it grew at a steady, predictable pace.

The US has now entered a new era of growth that requires a broader set of solutions.

Rapid demand growth is colliding with rising infrastructure costs, long resource-development timelines, affordability concerns, and the continued need to decarbonize the power system. Conventional grid investments alone cannot address all of these challenges.

Distributed energy resources (DERs) – such as distributed batteries, flexible electricity consumption, and distributed solar – have emerged as a particularly well-suited solution. Harnessing DER flexibility can make better use of assets and infrastructure already on the system by alleviating capacity constraints, generating electricity closer to where it is needed, and supporting a cleaner power system.

Many DERs have characteristics that are particularly well suited to these emerging power sector challenges, including:

- **Short development timelines**, which can accelerate the interconnection of new loads by several years relative to conventional, centralized sources of power generation;
- **Modular scale and flexible costs**, which allow DER capacity to be added as load grows – and scaled back when it does not – rather than requiring fixed, multidecade investment decisions based on highly uncertain load forecasts;
- **Located close to load**, providing valuable services to both the bulk power and distribution systems while avoiding energy losses from transmitting electricity over long distances;
- **Economically beneficial**, providing direct payments to participating households and businesses while reducing electricity rates for all customers as a cost-competitive system resource;
- **Clean**, providing flexibility that complements renewable generation, reduces curtailment, facilitates beneficial electrification, and reduces the need for fossil fuel-based sources of flexible generation.

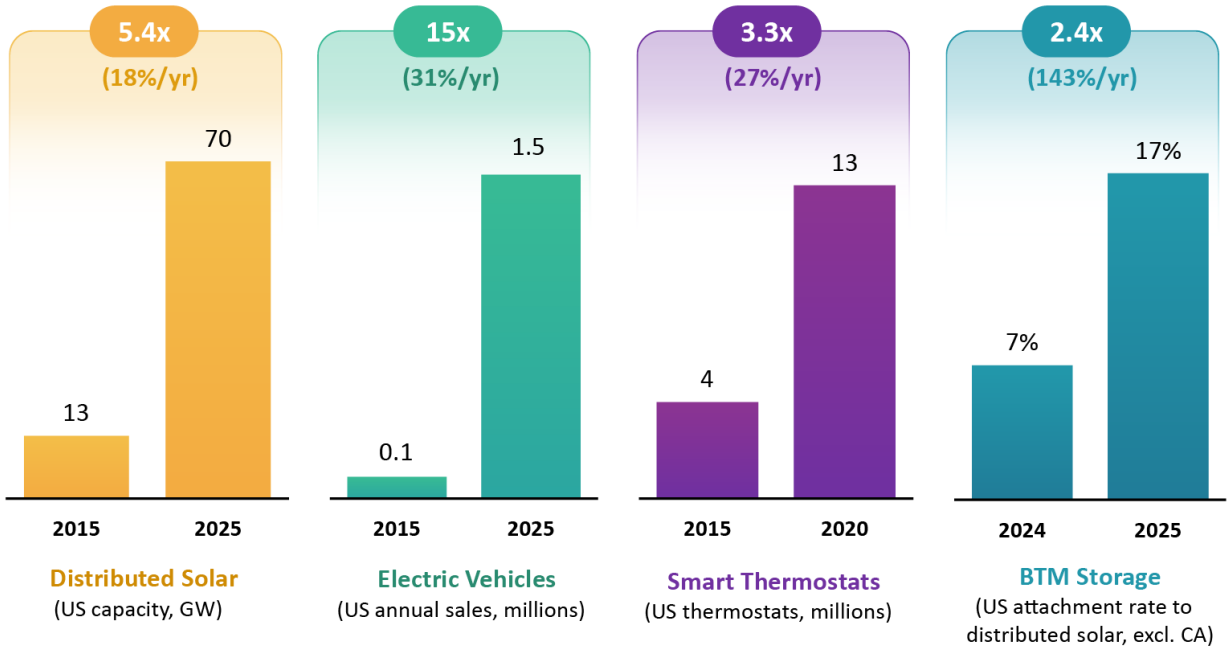
Consumers adopt DERs for many reasons. Households and businesses may choose batteries for backup power, electric vehicles (EVs) for fuel efficiency and advanced technology, or smart thermostats for ease

[3] Edison Electric Institute (EEI), Industry Capital Expenditures with Functional Detail, September 2025.

of use. Harnessing the flexibility of these assets offers an efficient, low-cost opportunity to provide services to the power grid while rewarding participants.

The DER opportunity is particularly important because of its growing scale: customer adoption is now measured in gigawatts and is expected to continue increasing. This trend, illustrated in Figure 1, is rapidly expanding the installed base of flexible, customer-owned assets that could provide grid services.[4]

FIGURE 1: RECENT GROWTH IN US DER ADOPTION



Note: Growth metrics are reported for the relevant years and vary by DER type based on data availability.

No single resource can solve all the challenges facing the grid. New generation, transmission, distribution infrastructure, and other resources will all be needed. DERs, however, could become a much larger part of the solution if current barriers to maximizing their value are addressed.

Purpose of this Study

In April 2026, The Pew Charitable Trusts (Pew) published a report titled *Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future* (the "Policy Playbook").[5] The report identified several policy changes that could remove barriers to DER deployment and better integrate DERs into utility planning, procurement, and operations (see the box "DER Deployment – Barriers and Solutions").

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[4] US Energy Information Administration (EIA), Electric Power Monthly, Table 6.1.A, 2025; Argonne National Laboratory, Light Duty Electric Drive Vehicles Monthly Sales Updates, September 2026; EIA, Residential Energy Consumption Survey, Table HC3.1, 2015 and 2020; Lawrence Berkeley National Laboratory (LBNL), Tracking the Sun: 2026 Data Update, August 2026.

[5] The Pew Charitable Trusts, *Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future*, April 2026.

Our study complements the Policy Playbook by quantifying the national scale and value of expanded DER deployment. Specifically, we address three overarching questions:

- How much additional DER capacity could be unlocked in the US by 2050 if existing barriers were removed, enabling nationwide deployment to reach adoption and participation levels already observed or projected in leading US markets?
- What impacts would that level of DER deployment have on the US power system in terms of investment and operations?
- How would those power system impacts affect energy affordability and environmental outcomes?

Our analysis focuses on the incremental benefits that could be unlocked through ambitious but feasible expansion of DER deployment relative to a status quo baseline. The study has a national scope with regional detail, considers opportunities across both the bulk power and distribution systems, and explores scenarios related to load growth uncertainty, power sector decarbonization, and policy impacts. The modeled portfolio includes non-emitting DERs across residential, commercial, and industrial customers, including flexible HVAC and water heating, managed and bidirectional EV charging, commercial and industrial demand response, and behind-the-meter and front-of-meter distributed solar and batteries.

The Remainder of the Report

The remainder of the report is organized as follows:

- Section 2 provides an overview of the study scope and analytical framework, combining long-term resource planning modeling with an assessment of distribution system impacts.
- Section 3 describes the opportunity to more than quadruple existing DER capacity and the resulting impacts on the US power system's capacity mix, operations, and carbon dioxide emissions.
- Section 4 analyzes how those power system changes could generate more than half a trillion dollars in resource cost savings over the 25-year study period and translate into household bill savings.
- Section 5 explores how increased reliance on DERs could reduce the cost risk of overbuilding the power system amid uncertain load growth by 40%.
- Section 6 analyzes how DERs could support a fully decarbonized power system while helping maintain affordability for consumers.
- Section 7 concludes the report by examining how three initiatives in Pew's Policy Playbook could unlock over 40% of the incremental benefits identified in this study.

See the accompanying Technical Appendix (Volume II) of this report for additional detail on methodology and data sources.

DER DEPLOYMENT – BARRIERS AND POLICY SOLUTIONS

Despite growing capabilities and declining costs, DERs continue to face policy and regulatory barriers that limit deployment and prevent them from competing on equal footing with conventional grid investments. Pew's Policy Playbook highlights several key barriers and steps that policymakers and regulators can take to address them.

Key barriers include:

- **Limited consideration in utility planning**. DERs are not consistently evaluated alongside generation, transmission, and distribution investments as potential solutions to grid needs.
- **Misaligned utility incentives.** Traditional cost-of-service regulation financially favors utility capital investment over customer-sited alternatives.
- **Slow and costly deployment processes.** Permitting and interconnection requirements can be fragmented, unpredictable, and expensive, adding significant "soft costs" to DER projects.
- **Limited pathways to capture grid value.** DER owners and aggregators may lack practical opportunities to provide – and receive compensation for – the full range of services their resources can offer.

The Policy Playbook identifies several opportunities to address these barriers:

- Integrate DERs into planning and procurement, including distribution planning, locational analysis, and virtual power plant (VPP) deployment targets.
- Align utility financial incentives so utilities can benefit when DERs avoid or defer more expensive infrastructure.
- Streamline permitting and interconnection through standardized requirements, clearer timelines, automation, and improved use of grid data.
- Create pathways for DERs to provide grid services, allowing customers and aggregators to be compensated for the value they provide.
- Deploy DERs strategically to enhance resilience, including through microgrids, resilience hubs, and VPPs that can support communities and critical loads during outages.

Section 7 of the report specifically quantifies how a subset of these solutions could help unlock the national benefits of DERs.

Section 2: Estimating the Benefits of DERs

This section provides an overview of the study scope and our approach to estimating the value of DERs. The accompanying Technical Appendix provides additional detail on modeling assumptions and data sources.

The DER Landscape

Defining "DER"

The term "DER" is defined in various ways. This study uses the definition adopted by Pew in its Policy Playbook:

> DERs are technologies that generate, store, or manage electricity close to where it is used, such as batteries, rooftop solar panels, community solar, managed electric vehicle charging, smart thermostats and appliances, and advanced building controls (systemwide automation that monitors and manages energy use in buildings). These technologies connect to the distribution system to help homes and businesses produce or control their electricity and to provide surplus power to the grid.

DERs Analyzed in This Study

We model the potential impacts of DERs across residential, commercial, and industrial customers, organized into three broad categories:[6]

Demand flexibility: Flexible electricity use can be shifted or reduced when the grid is constrained and increased when power is more readily available, thereby reducing peak demand, avoiding or deferring generation and network investments, and helping integrate variable renewable generation by better matching demand with supply. We model residential cooling, space heating, and water-heating flexibility, managed charging and bidirectional vehicle-to-grid capability for light-duty vehicles and medium- and heavy-duty fleets (including school buses), and automated and manually dispatched demand response from commercial and industrial customers.

Distributed solar: By producing electricity close to where it is consumed, distributed solar reduces the need for centrally generated energy and can lessen power flows across the transmission and distribution systems, particularly when production aligns with system or local peaks. Our analysis includes behind-the-meter (BTM) solar serving residential, commercial, and industrial customers, community solar, and front-of-meter (FTM) projects connected to the distribution system.

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[6] Other distributed resources, such as energy efficiency, could provide additional value. See Section 4 for discussion of additional distributed resources not included in this study.

Distributed batteries: Batteries can charge when demand and energy costs are low and discharge during peak or constrained periods, providing capacity, balancing variable generation, relieving local grid constraints, and improving customer resilience. We include BTM batteries at residential, commercial, and industrial sites, storage attached to community solar, and FTM batteries connected to the distribution system. For purposes of estimating dispatchable grid value, we count the portion of deployed batteries that can be dispatched to provide services directly to system operators (e.g., through enrollment in a VPP program).

A Broad Study Scope

National Breadth, Long-Term Study Horizon

Our analysis divides the US into 25 regions, which are defined primarily based on North American Electric Reliability Corporation (NERC) assessment regions and independent system operator/regional transmission organization (ISO/RTO) boundaries, with further subdivisions based on regional pricing zones.[7] Our characterization of load, supply mix, customer base, and resource costs is tailored to each region.

The study horizon extends through 2050. This long-term view provides perspective on DER deployment opportunities that are not constrained by current barriers. Where relevant, we also report results for intermediate years to provide medium-term benchmarks for initiatives intended to have an impact within the next decade.

Public, Credible Data Sources

Our analysis relies entirely on transparent, publicly available data and forecasts developed by organizations such as the National Labs, the US Energy Information Administration (EIA), the Electric Power Research Institute (EPRI), ISOs, utility and stakeholder regulatory filings, and other public industry reports. Our modeling assumptions were vetted by a technical advisory committee assembled by Pew and by external peer reviewers (see Acknowledgments). The Technical Appendix provides a detailed description of the data sources and how they were applied in our analysis.

Ambitious but Feasible Adoption

The level of national DER deployment assumed in this study is based, to the extent possible, on adoption and participation rates already observed or projected in leading US markets. For example, we assume that 45% of eligible US residential households eventually enroll in some form of air-conditioning load control. Xcel Energy has achieved this high level of enrollment in Minnesota, while Everyday Electric has exceeded it through its “Energy Shift” enrollment strategy (see the box “DER Adoption Success Stories” for further discussion). Emerging technologies, such as vehicle-to-grid, have less industry experience so we anchor assumptions on assessments of future technology potential.

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[7] We use the same geographic definition as the EIA’s *Annual Energy Outlook*. See Technical Appendix for further details.

Achieving that level of adoption will require overcoming a broad range of technical, regulatory, and market barriers that vary by state and utility territory. Addressing these barriers will require new policies, regulatory reforms, and market innovation, all of which will take time to implement. Accordingly, our regional analysis assumes a gradual ramp from current DER adoption to the maximum adoption levels modeled.

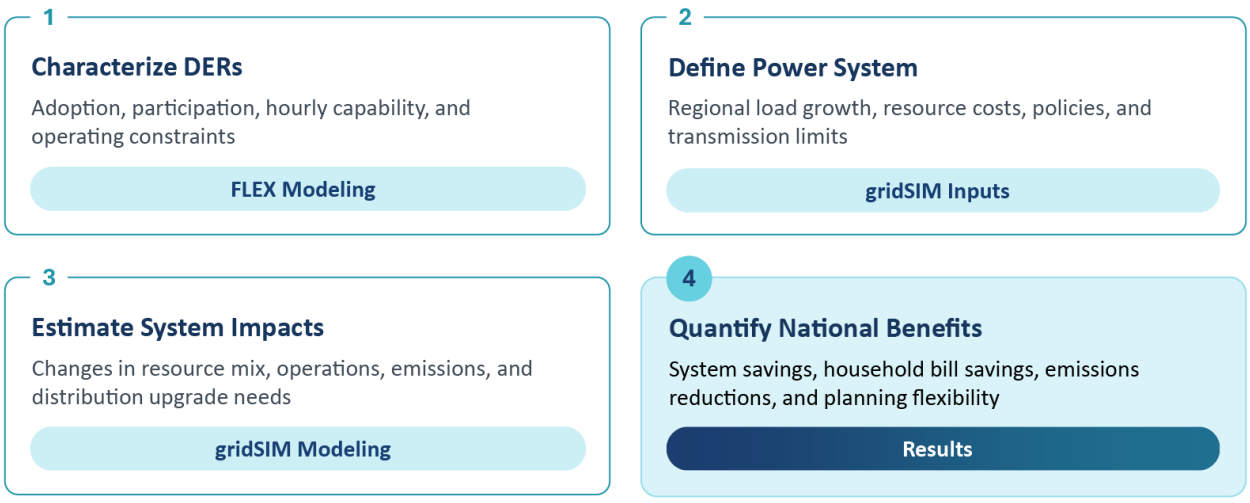
We do not assume universal customer participation or the realization of all technically feasible DER opportunities. Accordingly, the modeled deployment levels should not be interpreted as estimates of technical potential. Conversely, our estimates are not forecasts of what is likely to happen; they assume the removal of significant barriers to DER deployment.

Capturing the Full System Value of DERs

Our analysis estimates the value of DERs across the power system rather than for a single use case. DERs can affect generation needs, change system operations, and defer distribution system investment. The analytical framework captures these interconnected effects to estimate how greater DER deployment could change total system costs and, ultimately, customer bills.

The analysis combines two complementary perspectives: a bulk power simulation using Brattle's resource planning model (gridSIM) to dynamically estimate avoided generation investment and operating costs, and a top-down distribution system analysis to estimate opportunities to defer local infrastructure upgrades. Brattle's FLEX model characterizes the DER operating capability used in this systemwide analysis. The analyses use a shared set of regional assumptions, allowing bulk and distribution system value to be integrated into the estimate of systemwide benefits. Figure 2 provides an overview of the methodology.

FIGURE 2: METHODOLOGY OVERVIEW



Two Complementary Views of System Value

- **Bulk system:** We use gridSIM to simulate how the generation fleet expands and operates through 2050.[8] We account for regional demand, transmission limits, resource costs and availability, clean-energy requirements, and constraints on how quickly new resources can be built. DERs are modeled with technology-specific hourly availability and operating limits. The analysis measures how greater DER availability changes the mix of conventional resources built and operated.

- **Distribution system:** Distribution capacity expansion needs are driven by constraints on local substations, feeders, distribution transformers, and other equipment. Rather than model every US circuit, the analysis uses a top-down approach to project the distribution capacity expansion capex through 2050 and applies high-level assumptions to estimate the share of capex that can be deferred through DER deployment. These assumptions are informed by the results of more granular studies on the potential for DERs to defer distribution system investments at the utility jurisdiction level.

  The analytical approach begins with a regional projection of distribution capacity expansion spending, developed by extrapolating national distribution investment and allocating it to regions according to their share of load growth. The second step compares the regional load growth driving distribution capacity expansion with the peak load reduction potential of available DER capacity to estimate how much the pace of capital spending could be slowed if DERs were orchestrated to provide reliable distribution grid services. The orchestrated DER operation assumed in this scenario will require concerted action by utilities, regulators, DER companies, and customers.

Accounting for Data Center Growth

The emergence of data centers as a major new source of electricity demand changes the context in which DERs should be evaluated. Data centers are expected to drive a significant share of US load growth over the next decade, with large concentrations of new demand emerging in some regions. Our outlook relies on EPRI's recent regional assessment of announced projects and their likelihood of development.[9] In our study, data centers account for roughly 40% (58 GW) of national peak-demand growth by 2035 and 30% (121 GW) by 2050, when other sources of growth, such as electrification, carry relatively greater weight.

There is significant uncertainty about how quickly and at what scale data center projects will materialize. This uncertainty increases the value of DERs relative to other resources because they can be deployed

[8] We do not model transmission expansion dynamically since it has historically been a modest DER use case and requires nuances to capture accurately in a long-run planning model. Instead, we forecast new transmission investments based on the EIA AEO scenario aligned with our load forecast. While DERs could influence bulk transmission planning decisions, those avoided costs are outside the scope of the analysis. We do attribute value to DERs when displacing utility-scale generation capacity that includes plant-specific interconnection costs.

[9] EPRI, *Powering Intelligence 2026*, February 2026. We anchor assumptions on EPRI's medium projections.

quickly and incrementally – and potentially scaled back cost-effectively if the capacity is not needed.[10] We capture this "planning flexibility value" of DERs through separate analysis that tests how greater reliance on DERs could reduce the cost of overbuilding the system if anticipated data center demand does not materialize (see Section 5).

Representing DER Capability Realistically

Our analysis does not assume that every megawatt of technically deployable DER capacity becomes a grid resource. Brattle's FLEX model translates the underlying customer and technology base into achievable DER capability using participation rates, per-customer impacts, and operating constraints that vary by technology, customer class, region, and year. Where applicable, these inputs are supported by observed levels in various jurisdictions. These constraints include factors such as event frequency, charging requirements, state of charge, and hourly availability.

Representing these characteristics accurately matters because DERs are customer devices, not dedicated grid resources. A smart thermostat is not a gas turbine, and an EV is not a stationary battery. Their value depends on when they are available, how often they can be called, and the customer behaviors that drive the modeled megawatts.

Interpreting the Findings

These findings should be interpreted as an estimate of the potential value of expanded DER deployment under a defined set of assumptions, rather than as a prediction of future outcomes.

Actual benefits will depend on technology costs, customer participation, load growth, resource-market conditions, and the pace and effectiveness of policy and regulatory implementation. In particular, realizing distribution-system value requires DERs to be deployed at the locations and times they are needed and to be sufficiently visible, controllable, and dependable for utilities to incorporate them into planning and operations.

The national results necessarily abstract from local variation. Benefits may differ across markets and utilities, and distribution deferral opportunities require more detailed local analysis.

DERs are not substitutes for every conventional investment, and they will not eliminate the need to replace aging infrastructure, invest in resilience, or develop infrastructure to serve load growth. Nevertheless, the scale and consistency of the findings indicate that DERs could be a material, cost-effective component of the resource portfolio if the practical conditions needed to unlock their value are established.

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[10] While DER physical capacity will not be uninstalled in response to lower-than-expected demand, incentives to add new DERs or to operate existing DERs to provide headroom can be adjusted. In some cases, price signals to DERs reacting to a data center slowdown will naturally and efficiently reduce DER contributions when they are less needed.

DER ADOPTION SUCCESS STORIES

The following jurisdictions have achieved adoption levels comparable to or higher than those assumed in this study:

- **Residential HVAC**: Xcel Energy has enrolled more than half of eligible residential customers in Minnesota in air-conditioning load control.[11] In addition, 75% of Nest customers choose to enable Everyday Electric's daily "Energy Shifts" when setting up their thermostats.[12]
- **EV managed charging**: ConEd has enrolled 30% of its eligible EV customers in managed charging programs, and Consumers Energy has enrolled 22% of all EV owners in its managed charging pilot.[13]
- **Distributed solar**: Australia illustrates how deployment can accelerate when administrative and cost barriers are lower. Rooftop solar is installed on roughly one-third of suitable homes nationally, with adoption exceeding 60% in some local areas – a result supported by permitting policies that do not require local, state, or territory planning approval.[14]
- **Distributed storage**: Green Mountain Power has already enrolled roughly 2% of its residential customers in its battery program and forecasts participation of 9% to 15% by 2040.[15] California's Demand Side Grid Support (DSGS) program scaled to over 700 MW in less than three years.[16]

These examples do not imply that every US market will follow the same trajectory, but they demonstrate that the adoption levels are attainable rather than theoretical. Reaching them nationally would require sustained progress on customer engagement, program availability, compensation, permitting, interconnection, and other barriers discussed throughout this report.

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11 Xcel Energy, 2020-2034 Upper Midwest Resource Plan, Appendix G-1 – Demand Side Management, July 2019.

12 Everyday Electric (formerly Renew Home), March 2025.

13 Joint Utilities of New York, *Comprehensive Managed Charging Report*, March 2026; Alliance for Transportation Electrification, *Driving Participation in Managed Charging Programs*, August 2025.

14 Australian Government Clean Energy Regulator, December 2024; International Energy Agency (IEA), National Survey Report of PV Power Applications in Australia 2024, November 2025; Australian Government Department of Climate Change, Energy, the Environment and Water, Federal Solar Consumer Guide.

15 Green Mountain Power, 2024 Integrated Resource Plan.

16 The Brattle Group, *The Demand Side Grid Support Program: An Assessment of Scale and Value*, December 2025.



Section 3: A More Distributed Power System

This section examines the impacts of expanded DER deployment on the US power system, focusing on changes in the supply mix, system operations, and distribution system upgrades.

Quadrupling National DER Deployment

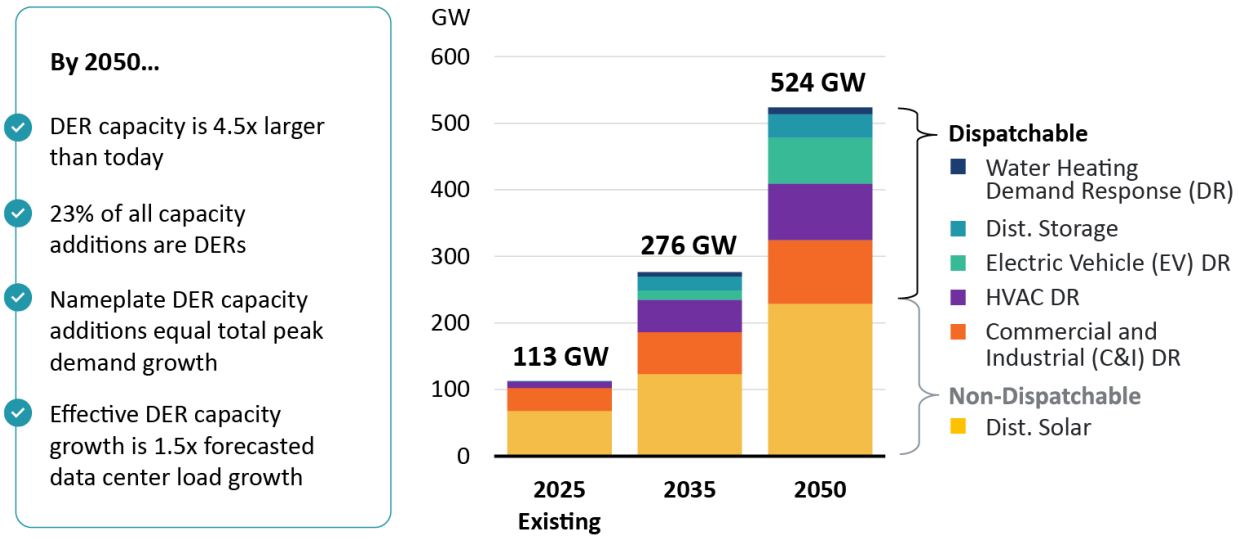
Collectively, DERs have already become a sizable national power system resource. The US currently has 113 GW of nameplate DER capacity.[17] This total comprises 68 GW of distributed solar, 44 GW of demand flexibility, and 1 GW of distributed storage enrolled in VPP programs.[18] Total nameplate DER capacity represents roughly 8% of installed US generation capacity today. DERs rank behind gas, coal, and large-scale wind and solar, but ahead of hydro, nuclear, and utility-scale storage.

Removing deployment barriers could unlock flexible DER capacity at a national scale. Under the expanded deployment forecast in this study, total nameplate capacity would increase to 524 GW by 2050 (229 GW of distributed solar, 259 GW of demand flexibility, and 35 GW of distributed storage enrolled in VPP programs). That is 4.5 times current DER capacity. At that level, **DERs would become the fourth-largest resource in the US capacity mix and account for nearly 20% of installed capacity in 2050**. Figure 3 summarizes the projected level of DER deployment relative to current capacity.

[17] "Nameplate capacity" refers to total installed capacity. This is different (higher) than accredited capacity, which accounts for the availability of the resource to provide power to the system when it is needed to maintain resource adequacy.

[18] We explicitly model, and report, the subset of distributed storage capacity expected to be enrolled in controllable demand response or VPP programs; the amount of distributed battery capacity currently on the grid exceeds the enrolled 1 GW value reported here. Additional BTM capacity is deployed through 2050 but does not provide comparable grid services unless controlled through a utility, aggregator, or other program. EV managed charging is included in the "demand flexibility" category.

FIGURE 3: US DER INSTALLED CAPACITY (NAMEPLATE)



Note: Growth drivers include rooftop solar on one in six single-family homes; 15%–45% customer participation in flexible load offerings, depending on the offering; distributed resources accounting for 21% of all storage additions; and additional front-of-meter solar and commercial and industrial (C&I) flexibility.

Forecasted load growth provides useful context for these capacity additions: **411 GW of nameplate DER capacity additions by 2050 is roughly equivalent to total forecasted load growth over that period**. On an accredited capacity basis, the growth in DER capacity is roughly 1.5 times the total forecasted load growth from data centers.[19]

Growth in demand flexibility is a major driver of this outcome. Total demand flexibility increases more than sixfold relative to current capability. In the near term, growth is driven by latent potential in residential HVAC (e.g., smart thermostats) and commercial and industrial building automation. Over the longer term, EVs emerge as an important source of flexibility, particularly as bidirectional charging matures. The potential for distributed storage – both BTM and FTM – is a consistent driver of the opportunity throughout the study horizon.

By comparison, if existing barriers to deployment are not addressed, less than half of the forecasted DER capacity growth (196 GW) would materialize by 2050. Most of the increase would come from continued growth in distributed solar and would depend heavily on the continuation of existing solar compensation policies; growth in other DER types would be modest. In this report, the incremental benefits of expanded DERs are reported relative to this status quo baseline.

[19] Forecasted data center growth is around 120 GW. Strictly for illustrative purposes in this example, we assume accredited capacity is equal to 5% of installed capacity for distributed solar, 60% for distributed storage, and 75% for demand flexibility, based on a review of average ISO/RTO accreditation values today and projections from NLR.

Less Gas, More Renewables

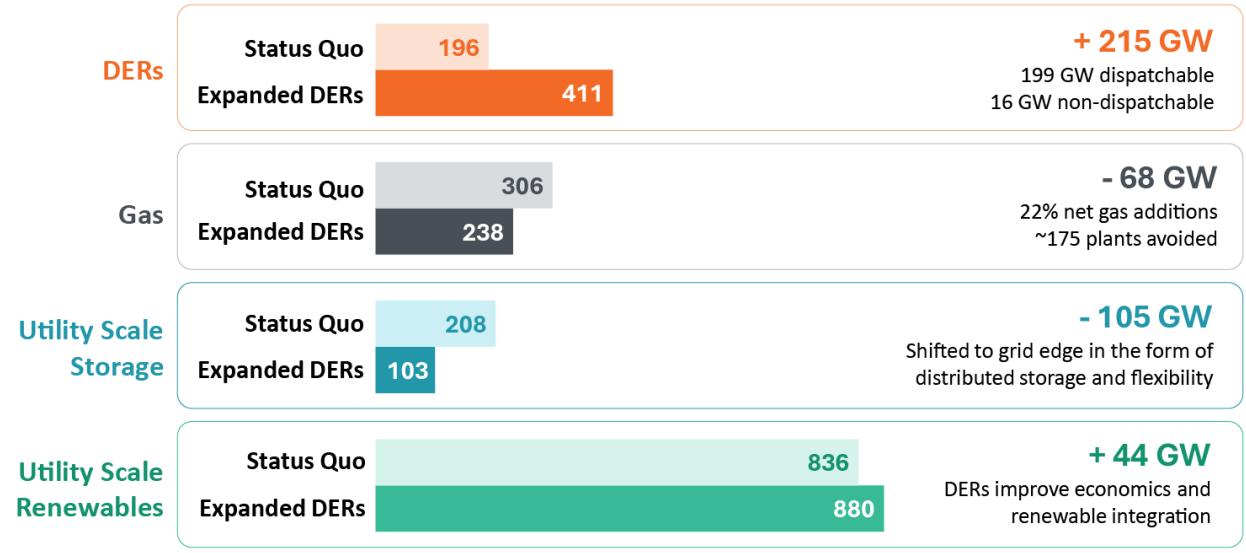
What would adding roughly 400 GW of DER capacity mean for the rest of the US power system? First, this expanded deployment would reduce the need for new gas generation. **Specifically, roughly 70 GW of gas generation would be avoided between 2030 and 2050, representing a 22% reduction in net gas additions – the equivalent of approximately 175 gas plants**.[20]

Fully unlocking DERs would also shift storage capability to the grid edge, where it can provide value to both the bulk power and distribution systems. Roughly 105 GW of utility-scale storage is replaced with distributed storage and other forms of distributed flexibility, representing around half of net utility-scale storage additions.[21]

Conversely, utility-scale renewable generation capacity additions *increase* with greater reliance on DERs. Distributed flexibility economically complements renewables, and vice versa: while renewables provide inexpensive energy but do not significantly address capacity needs, DERs provide the flexibility to "firm up" renewables and reduce curtailments. As a result, output from wind and solar generation increases by roughly 3% over the full study period.

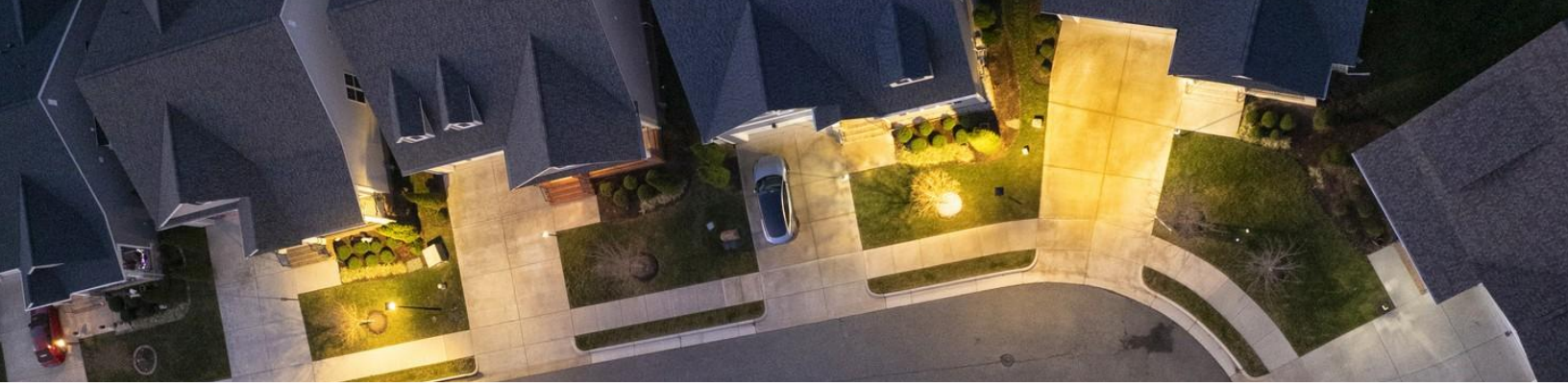
Figure 4 highlights the change in nameplate capacity additions from 2026 to 2050 due to the introduction of an expanded DER portfolio. The results are shown relative to a scenario in which DER deployment continues along a status quo trajectory.

FIGURE 4: US NAMEPLATE CAPACITY ADDITIONS, 2026–2050



[20] The displaced gas capacity is a combination of approximately 50 GW of avoided additions and 20 GW of additional economically driven retirements.

[21] While beyond the scope of this study, we note that location-specific transmission needs such as reactive power and voltage support could limit the ability of distributed storage to substitute for utility-scale storage



A More Efficient Distribution System

DERs are more than a bulk system capacity resource. Because they are located at the grid edge, close to load, they can delay investment in upstream assets, including load-driven distribution system upgrades. However, DERs can address only a portion of distribution system upgrade needs.

Between 2010 and 2025, the US spent $760 billion on the distribution system,[22] but only about 30% of distribution capital expenditures support load-growth-driven capacity expansion.[23] This implies average annual distribution capacity expansion spending of $15 billion over the past 15 years. Extrapolating this trend and adjusting annual spending in proportion to forecasted annual load growth suggests that cumulative distribution capacity expansion capex could be roughly $820 billion between 2026 and 2050.

Because these needs are largely driven by load growth, DERs that reduce local peak demand could slow the pace of spending. Other distribution costs unrelated to load growth include replacing aging infrastructure, hardening the grid against extreme weather, and improving IT systems, among other needs. These needs are generally not addressable by DERs and are not considered to be a DER value stream in this analysis.

Of the growth-driven upgrade needs, 60% may have characteristics that allow them to be deferred with DERs.[24] These characteristics could include overload hours that fall within DER dispatch constraints and distribution investments in areas with sufficient local DER capacity.

The distribution system upgrades considered eligible for deferral in this analysis represent roughly 130 GW of new capacity through 2050. Geographically targeted DER deployments have the potential to defer many of these upgrades. By comparison, our estimate of nameplate DER capacity in 2050 exceeds this need by a factor of four, and the DER capacity available during peak load hours is about 117 GW. This suggests that, if DER capacity is deployed in time to meet system needs and is strategically sited and operated to provide distribution grid services, it could defer up to 90% of eligible capital expenditures.

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[22] Federal Energy Regulatory Commission, Form 1 – Electric Utility Annual Report, 2026. Note: Inflation-adjusted 2026 dollars, undiscounted. We apply an additional adjustment because FERC Form 1 data is missing a portion of US utilities. The raw FERC Form 1 inflation-adjusted, undiscounted 2010-2025 distribution spend is $0.58 trillion.

[23] LBNL, Electric Utility Distribution Costs, May 2026.

[24] This estimate is informed by Brattle's work across various US distribution utilities and represents investments in the secondary distribution system and other types of upgrades that may be infeasible or difficult to address with DERs.

Deferral periods are likely to depend on load shapes and the extent to which sufficient DER capacity is deployed in time to meet local load growth. The analysis assumes an average deferral period of five years.

Figure 5 summarizes the distribution system deferral opportunity for DERs relative to the total investment requirement from 2026 through 2050.

FIGURE 5: CUMULATIVE DISTRIBUTION UPGRADE DEFERRAL VALUE OF DERS THROUGH 2050



Distribution upgrade deferrals will not occur automatically. In addition to geographically targeted DER deployment, distribution system operators need sufficient visibility into and control over DERs to incorporate them into system planning and operations. At scale, DERs must also be operated in a grid-aware manner that avoids creating new capacity constraints – for example, through the simultaneous charging of large numbers of EVs and standalone batteries in one location. If enabled, this type of orchestrated DER deployment and operation would allow distribution system operators to use DERs to prevent grid constraints.

Section 4: An Affordability Solution

This section examines the economic benefits of expanded DER deployment. We first describe avoided resource costs and then explore how those savings could translate into lower consumer bills.

A $600 Billion Opportunity

DERs reduce the overall cost of operating the US power system by avoiding or deferring investment in traditional grid infrastructure, including power plants and the distribution system. By 2035, an expanded DER portfolio could avoid $19 billion per year in large-scale generation and distribution system costs. These annual benefits increase as DER deployment scales, reaching $43 billion per year by 2050. **Across the 25-year study horizon, cumulative avoided costs total $614 billion (inflation-adjusted and undiscounted).** [25]

How the value breaks down:

- By 2050, over half of the cumulative value ($334 billion) is due to **avoiding generation costs** (both capital and operating expenditures). Generation resources would no longer need to be built and operated solely to serve peak demand during a limited number of hours each year. This savings opportunity is driven in part by the rapidly rising installed cost of competing natural gas generation, which has doubled over the past four years and remains a significant near-term affordability concern.[26]
- Roughly one-third of the cumulative value ($182 billion) is due to **deferring load growth-driven investments in the distribution system**. Distribution costs have recently been a leading driver of rising household electricity bills, so resources that mitigate this growth can help address a key affordability challenge.[27]
- The remaining portion of the cumulative value ($97 billion) is due to a **reduction in the ratepayer cost of distributed solar**, which could be achieved through interconnection and permitting reform, as discussed later in this report (see Section 7).[28]

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[25] Throughout this report, unless otherwise noted, values are reported in undiscounted, inflation-adjusted 2026 dollars. We assume average annual inflation of 2.5% over the 25-year study horizon.

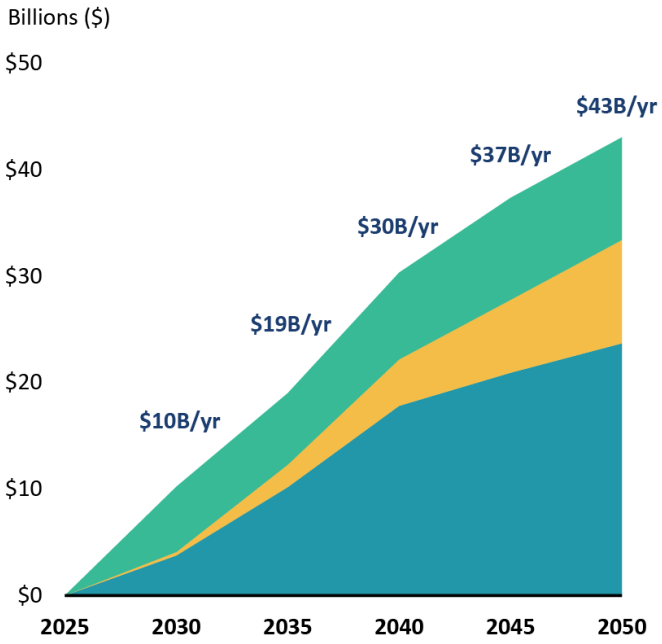
[26] The Brattle Group, *2022 PJM CONE 2026/2027 Report*; The Brattle Group, *2025 PJM CONE Study*; E3, RECOST Q3 2026 Update; OG&E, 2026 Integrated Resource Plan; GridLab, *2025 Gas Turbine Costs Report*; Enverus, *2026 PJM Market Report.*

[27] LBNL and The Brattle Group, *Retail Electricity Price Trends and Drivers: Data Update–2026 Edition*, July 2026.

[28] Specifically, we assume similar levels of distributed solar growth in both the status quo baseline and the expanded DER scenario. In both scenarios, we assume adopters of distributed solar earn a reasonable payback on their investment, which would effectively be funded in part by all utility customers if distributed solar compensation exceeds the value it provides to the power system. The primary difference in the expanded DER scenario is that the installed cost of distributed solar has decreased, so compensation can be reduced to a more financially sustainable level, easing or removing the burden on existing non-solar customers.

Figure 6 summarizes the incremental annual avoided resource costs attributable to the expanded DER portfolio, relative to status quo levels of DER deployment. Importantly, the values reported here include only avoided costs. They do not account for the additional costs of enabling DER deployment or compensating customers for providing grid services. Those costs and their impact on energy affordability and equity are discussed next.

FIGURE 6: ANNUAL US ELECTRIC SYSTEM AVOIDED RESOURCE COSTS



Reduced Distribution System Investment
Cumulative savings: $182B (30% of total)

When DERs are integrated into distribution planning and operated in coordination with grid needs, they can slow the rate of grid capacity expansion.

Distributed Solar Cost Reductions
Cumulative savings: $97B (16% of total)

Improved permitting and interconnection policies decrease costs to deploy distributed solar, which can be shared with all ratepayers by enabling financially sustainable solar compensation frameworks.

Reduced Generation Costs
Cumulative savings: $334B (55% of total)

DERs displace a portion of investments in utility-scale generation by providing flexibility and energy.

$614 billion
in cumulative avoided resource costs over 25 years (inflation adjusted and undiscounted)

Improving Energy Affordability for Households

Energy affordability has become a major concern for policymakers, regulators, utilities, and customers. US residential electricity rates rose 32% from 2020 to 2025[29] in nominal terms, compared with a roughly 24% increase in overall consumer prices,[30] and the US EIA expects rates to rise further in 2026.[31] This sustained pressure on household bills has sharpened the need for cost-saving solutions.

[29] EIA, Average Price of Electricity to Ultimate Customers by End-Use Sector, Electric Power Monthly, Table 5.3, accessed October 3, 2026.

[30] US Bureau of Labor Statistics, Consumer Price Index, All Urban Consumers (CPI-U), US City Average, annual averages, accessed October 3, 2026.

[31] EIA, Short-Term Energy Outlook, accessed October 3, 2026.

Prior to the recent escalation, electricity rates generally increased in line with overall inflation. Although the cost of an essential service such as electricity will always be an important policy consideration, rate growth in line with inflation reflected a broadly sustainable trajectory. Our study therefore evaluates the extent to which DERs could help return electricity rate growth to that inflation-aligned trajectory.

Our analysis assumes a status quo trajectory in which residential electricity rates – and, similarly, household bills – grow 0.5% per year faster than inflation over the 25-year forecast horizon, consistent with US Energy Information Administration projections.[32] This assumption reflects a gradual slowing of the recent trajectory as supply constraints ease, but not a full return to the historical pattern of growth roughly in line with inflation. Absent intervention, we assume retail electricity rates will rise because of factors such as load growth, the ongoing need to replace aging grid infrastructure, and investments required to prepare for and recover from increasingly volatile weather, among others.

Under this status quo trajectory, annual residential electricity bills would be $232 higher in 2050 than today, in inflation-adjusted terms. In other words, the average US household bill would increase from $1,855 to $2,087 per year in today's dollars, intensifying the affordability challenge.

DERs can play a major role in returning electricity bill growth to a sustainable path. After accounting for the cost of enabling DER deployment (technology investment, program administration, and marketing),[33] the resource cost savings described above would reduce average household bills by $122 per year by 2050.[34] **Those savings would cut the projected "real" (i.e., inflation-adjusted) increase in household bills roughly in half, bringing bill growth back toward its historical trajectory, when electricity bills generally grew in line with inflation**. DERs are not a complete solution, but they could make a significant contribution to restoring that more sustainable trajectory of bill growth.

Figure 7 illustrates the projected increase in inflation-adjusted annual household electricity bills with and without an expanded DER portfolio.

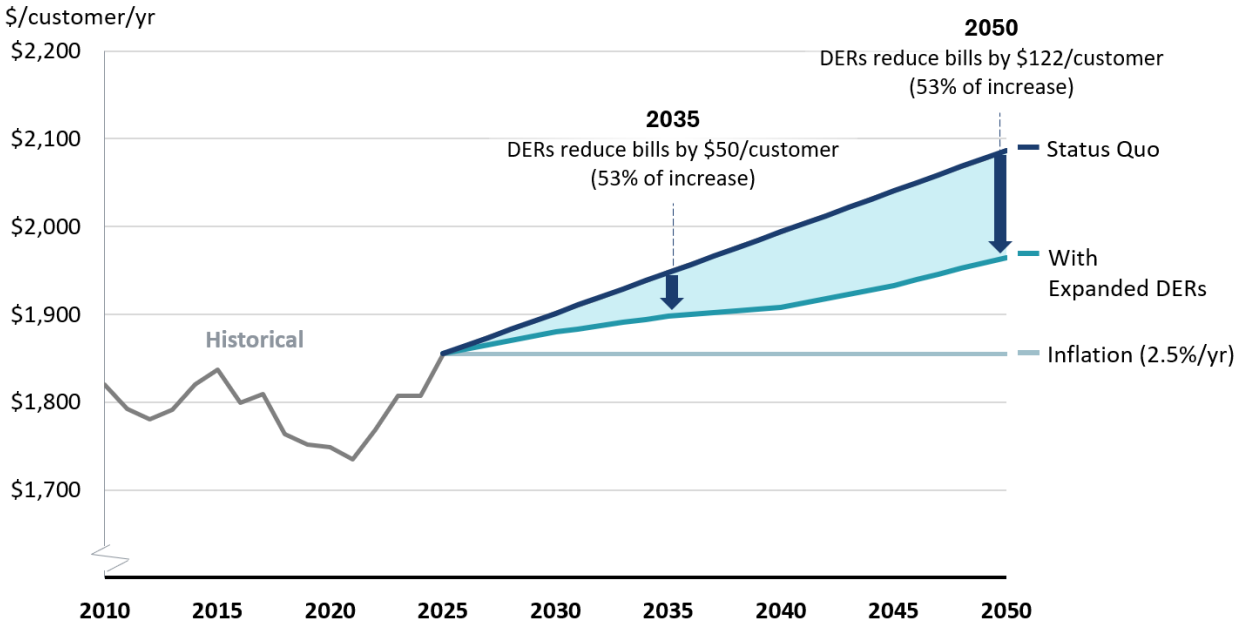
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[32] The status quo rate growth trajectory in the figure is based on an assumed 0.5% average annual real growth across the full study horizon. This forecasted increase in residential electricity rates aligns with the US EIA's 2026 Annual Energy Outlook, which reports an increase between 0.2% and 0.9% across scenarios and includes baseline generation and distribution system investment requirements that are similar to our modeled results. Future research could refine this outlook to estimate how the growth rate may change across the study horizon.

[33] The available value for residential participants and non-participants excludes $4.4 billion (out of $26 billion) reserved for implementation costs, assuming costs of around $40/kW-yr. Although many DERs involve investments by the customer, the DERs also provide private, non-system value to the customer. Our estimate of costs considers the net cost of installing and operating the equipment beyond what the customer would be willing to pay for its private value.

[34] Our analysis assumes roughly 60% of the savings will be allocated to residential customers, consistent with their contribution of total DER capacity. This is conceptually consistent with current ratemaking practices, which allocate capacity costs to customer classes based on their contribution to system peak demand.

FIGURE 7: US AVERAGE ANNUAL RESIDENTIAL ELECTRICITY BILLS (INFLATION-ADJUSTED 2026 DOLLARS)



Notes: The status quo rate growth trajectory is based on an assumed 0.5% average annual real growth in residential electricity rates across the full study horizon, consistent with projections in the EIA's Annual Energy Outlook. For comparison purposes, this assumes no change in annual residential electricity consumption. Changes in electricity consumption would alter the average bill trajectory, but that consideration is separate from the affordability impact analyzed here.

How the Benefits Are Shared

Thus far, our discussion of bill savings has focused on the average residential household. That average includes participants who are compensated for services provided by their DERs and non-participants (i.e., all other households). An important question is how the estimated $122 in average annual household savings by 2050 would be shared between households with DERs and those without.

A portion of the resource cost savings will need to compensate DER participants for adopting the technology and using it to provide grid services.[35] From a policy and program design perspective, compensation must be high enough to encourage participation while ensuring that non-participants also benefit materially.

[35] This compensation could be structured in a variety of ways. It could include direct performance payments (e.g., through utility VPP programs), bill savings from responding to a time-varying retail electricity rate, or up-front technology adoption incentives, among other options. In practice, a combination of these options is being used and will continue to be used. Given the national breadth of our scope, we are agnostic to the specific mechanism through which the compensation is delivered.

Our analysis shows that the resource cost savings from DERs are large enough to provide policymakers, utilities, and regulators with a range of options for allocating the benefits. To illustrate, consider the following scenarios:

- **Scenario 1 – Prioritizing rate reductions:** If performance compensation is near the lower end of levels that have proven effective (i.e., approximately $50/kW-year),[36] nearly three-quarters of the net benefits of DERs would create general downward pressure on rates. By 2050, the average non-participant would save $90 per year, while the average participant would save $164 per year, including additional DER performance compensation.[37]
- **Scenario 2 – Higher performance compensation:** At a higher compensation level of $100/kW-year, approximately half of the net benefits would be allocated to performance compensation. By 2050, the average non-participant would save $57 per year, while the average participant would save $206 per year, largely negating the forecasted bill increase beyond inflation.

In all cases, a portion of the available cost savings is offset by implementation costs. These costs include funding to facilitate DER deployment and orchestration, including investment in enabling infrastructure such as distributed energy resource management system (DERMS) platforms, fees for program administrators or aggregators, measurement and verification, and marketing.

Importantly, implementation costs are typically modest relative to the value of the DERs they enable. In this study, DER cost savings exceed our rough estimate of implementation costs by a factor of five. **As a result, approximately 80% of the value created by DERs can be returned to consumers through performance compensation or downward pressure on rates.** If implementation costs evolve at a higher level than our estimate, the benefits still provide significant financial headroom for net household savings.

Of course, performance compensation is not the only factor that drives enrollment. Other considerations, such as a seamless enrollment experience and consumer trust in the counterparty, may be more important than financial compensation.[38] Further research will help to determine the relationship between performance compensation and participation, identify the optimal level at which to set compensation, and determine how to effectively engage consumers in other ways.

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[36] For example, the all-in average compensation for residential participants in highly subscribed utility smart thermostat programs is often in the range of $50/kW-yr.

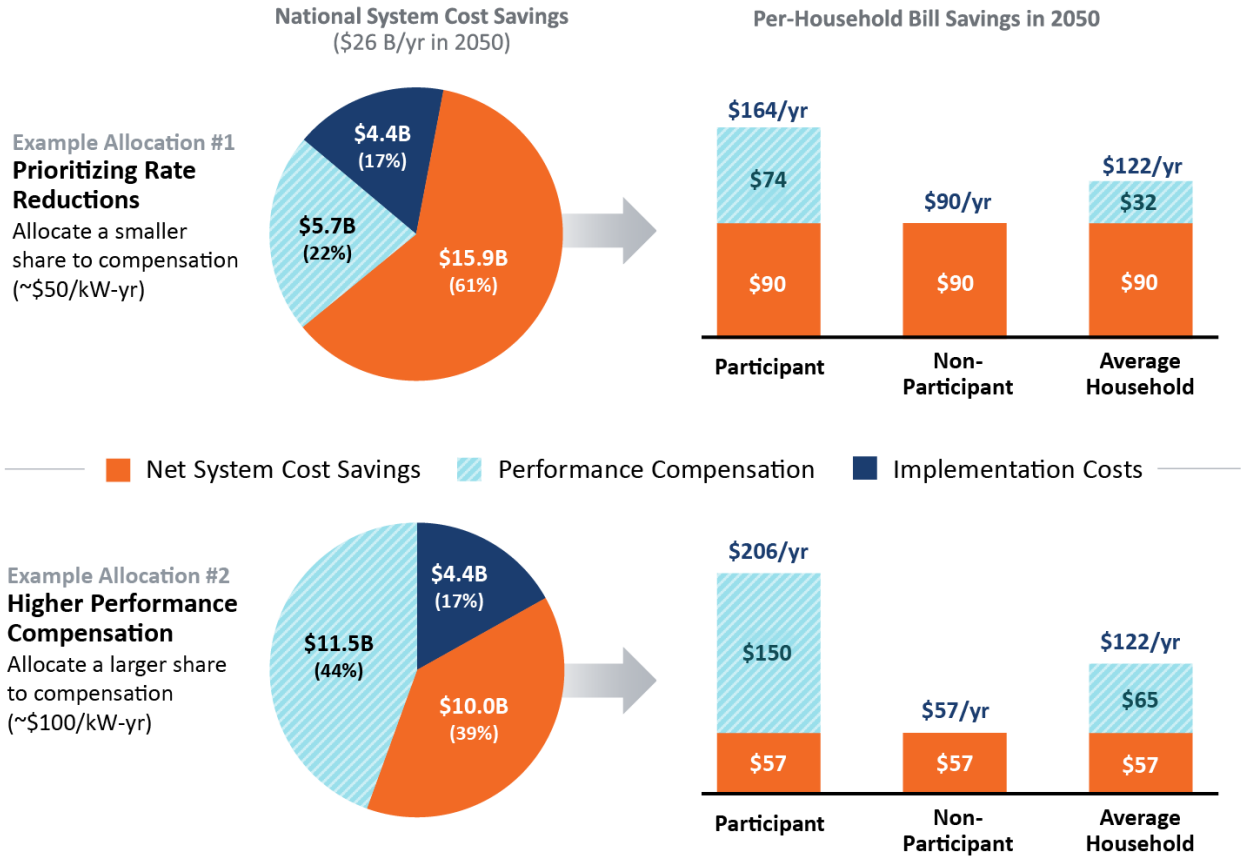
[37] Participant compensation will vary depending on which program(s) the customers are participating in, and which services they are providing. To determine the split between participants and non-participants, we assume that a portion of participants in EV, water heating, and battery demand response (DR) programs are also enrolled in HVAC DR.

[38] The Brattle Group and LBNL, *Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment*, 2024. This report discusses proven methods for increasing enrollment in demand flexibility offerings. The Brattle Group, *The Affordability Advantage: How Residential VPPs can Reduce Household Electricity Bills*, 2026. This report discusses how original equipment manufacturer (OEM)-led enrollment methods can unlock new participation.

The net benefits are also large enough to support regulatory frameworks that incentivize utilities to procure DER services and offset potential earnings they forgo by avoiding infrastructure investment. Options to better align utility financial incentives with the DER opportunity are discussed further in Pew's Policy Playbook.

Figure 8 summarizes how DER benefits are allocated between participants, non-participants, and implementation for the two scenarios described above.[39]

FIGURE 8: ALLOCATION OF DER BENEFITS TO AVERAGE US HOUSEHOLDS (2050)



Note: Both allocations assume a portion of households have multiple types of DERs. Values are inflation-adjusted to today's dollars.

[39] The figure shows $26 billion/year in system cost savings. That is the residential share of the $43 billion/year in total savings reported earlier.

Considerations for Low-Income Households

Expanded DER deployment can lower electricity costs for all customers, including households that do not own or participate in DERs. However, upfront technology costs and other obstacles[40] can make it harder for low-income households to capture the additional benefits available to participants.

No single solution can address this challenge. Experience with low-income energy programs points to several complementary approaches:

- **Targeted incentives and grants**. Higher incentives can reduce or eliminate upfront costs for qualifying households. When Inflation Reduction Act (IRA) rebates became available, the adoption potential for heat pump water heaters, heat pump space heating, and electric cooking more than doubled among low-income households.[41] PSEG Long Island has similarly offered storage incentives for low-income customers at twice the standard level. [42]
- **Accessible financing and alternative ownership models**. Zero- or low-interest financing and on-bill repayment can spread upfront costs for solar PV or heat pumps over time,[43] although traditional loan programs have struggled to reach lower-income customers. Inclusive utility investment models, such as on-bill tariffs, can go further by eliminating credit checks and tying repayment to the utility meter rather than the individual customer.[44]
- **Community-scale deployment**. Community solar, storage, and microgrids can extend DER benefits to renters and households that cannot install equipment themselves. Illinois Solar for All, for example, enables income-eligible households to access rooftop or community solar with no upfront cost and guaranteed electricity-bill savings.[45]
- **Lower-friction participation**. Streamlined enrollment and eligibility verification, coordination with existing assistance programs, and partnerships with trusted community organizations can reduce administrative and informational barriers to participation. DOE's Clean Energy Connector, for

[40] See The Brattle Group, *New York's Grid Flexibility Potential*, Volume III, prepared for NYSERDA and the New York Department of Public Service, 2025. The report describes additional barriers.

[41] Jordan M. Joseph et al., "Rebates and grid decarbonization from the Inflation Reduction Act promote equitable adoption of energy efficiency retrofits," *Environmental Research Letters*, in press, 2024. Adoption potential is a metric used by this article to represent the discounted cost-basis of a technology over its lifetime. Households are identified as potential adopters if they achieve a positive net present value through operational cost savings overcoming the capital expenses.

[42] PSEG Long Island, *Utility 2.0 Long Range Plan & Energy Efficiency Plan, 2023 Annual Update*, prepared for Long Island Power Authority, July 1, 2023.

[43] NYSERDA, Residential Financing Programs. NYSERDA's EmPower+ program is designed to assist low- and moderate-income homeowners and renters by providing no-cost home energy assessments, installations, and funding for energy efficiency improvements.

[44] Holmes Hummel and Harlan Lachman, "What is inclusive financing for energy efficiency, and why are some of the largest states in the country calling for it now?," Energy Efficiency Institute and Clean Energy Works, 2018. If the levelized cost of the technology is less than 80% of savings, then the costs can be reduced.

[45] Illinois Power Agency, Illinois Solar for All, accessed October 3, 2026; Kari Lydersen, "Illinois Solar for All is, at last, taking off," *Canary Media*, August 3, 2026.



example, uses existing Low Income Home Energy Assistance Program (LIHEAP)[46] eligibility to connect income-qualified households with community solar subscriptions, simplifying customer qualification and enrollment.[47]

These approaches illustrate that equitable DER deployment requires more than broad program availability. Well-designed programs can expand access to the direct benefits of participation.

Unquantified Benefits, Additional Value

The benefits quantified in this study do not capture the full value that DERs can provide to customers and the power system. Several additional benefits could become increasingly important as electricity demand grows and grid constraints intensify:

- **Faster capacity.** DERs can help meet growing demand from electrification while larger infrastructure projects are developed. DERs can be deployed more quickly than conventional infrastructure because they are modular and do not face supply chain backlogs or long interconnection delays. Perhaps most importantly, many of these devices have already been installed by consumers, creating latent flexibility that can be tapped at the grid edge. This makes DERs one of the few resources capable of responding to near-term capacity constraints while larger generation and grid upgrade projects are developed.
- **Improved resilience.** Customer-sited solar, batteries, and bidirectional EVs can provide backup power during outages, while community-scale resources can support critical facilities and neighborhoods when configured as microgrids. These benefits are tangible to participating customers even when their value is not fully reflected in traditional power-system cost models. Green Mountain Power, for example, uses thousands of customer batteries as a grid resource while also providing households with backup power.[48]
- **Expanded customer value.** Well-designed DER programs can lower the upfront cost of useful technologies. Discounted battery leases, free or subsidized smart thermostats, and managed-charging incentives can broaden access to devices with additional intrinsic benefits, such as improved convenience or comfort.

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[46] Government of the District of Columbia, Department of Energy and Environment, accessed October 3, 2026.

[47] US Department of Energy, Clean Energy Connector, accessed October 3, 2026.

[48] Green Mountain Power, "GMP's Growing Stored Energy Network Delivers $6M in Savings During July Heat Wave and Provides Lasting Year-Round Benefits for Customers," July 28, 2026.

- **More efficient use of the transmission system.** Because they are sited close to load, DERs may provide transmission system benefits by reducing peak flows, relieving local congestion, or deferring suitable transmission investments. This opportunity is highly location-specific and has been difficult to monetize because of the transmission network's complexity. However, new initiatives are emerging: PG&E, Google, and several DER companies have initiated a pilot to assess the potential for distributed flexibility to alleviate constraints on a transmission line in California.[49]

Additional DERs Could Further Increase Quantified Benefits

Several additional resources fit within some definitions of "DER" but were considered outside the scope of this study. Extending the research to incorporate these technologies and mechanisms could significantly increase the total identified benefits.

- **Energy efficiency.** Efficiency improvements drive reductions in energy use and infrastructure requirements. According to the US EIA, utility-administered energy efficiency programs alone delivered 24 terawatt-hours of incremental annual energy savings and 8 GW of incremental peak demand savings nationally in 2025.[50] Advanced analytics and hosting capacity studies increasingly enable utilities to identify locations for targeted efficiency that can create new headroom and be integrated into non-wires alternative (NWA) procurements and distribution planning processes.

- **Data center flexibility.** Data centers can directly reduce their power system impacts through operational adjustments or on-site generation. Google has signed several contracts with utilities to provide flexibility in return for accelerated interconnection.

- **Grid-enhancing technologies (GETs).** These technologies can increase the usable capacity of existing transmission and distribution assets through advanced monitoring, control, and power-flow optimization. Technologies such as dynamic line ratings, power flow controllers, and advanced conductors can often be deployed more quickly and at lower cost than traditional infrastructure upgrades.

- **Smart panels.** This emerging technology manages customer demand through circuit-level monitoring and control. Smart panels can disconnect specific circuits as needed to manage a home's demand and may serve as a gateway for metering or controlling devices within the home.

- **Time-varying rates.** These rates provide customers with a financial incentive to shift consumption to off-peak hours. Today, nearly 80% of residential customers are offered a time-of-use (TOU) rate by their utility. Some utilities – including California's investor-owned utilities, the Long Island Power Authority in New York, and Xcel Energy in Colorado – have made TOU rates the default offering for their customers.

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[49] Rewiring America, Introducing SHARE by PG&E, Google, and Rewiring America, accessed October 3, 2026.

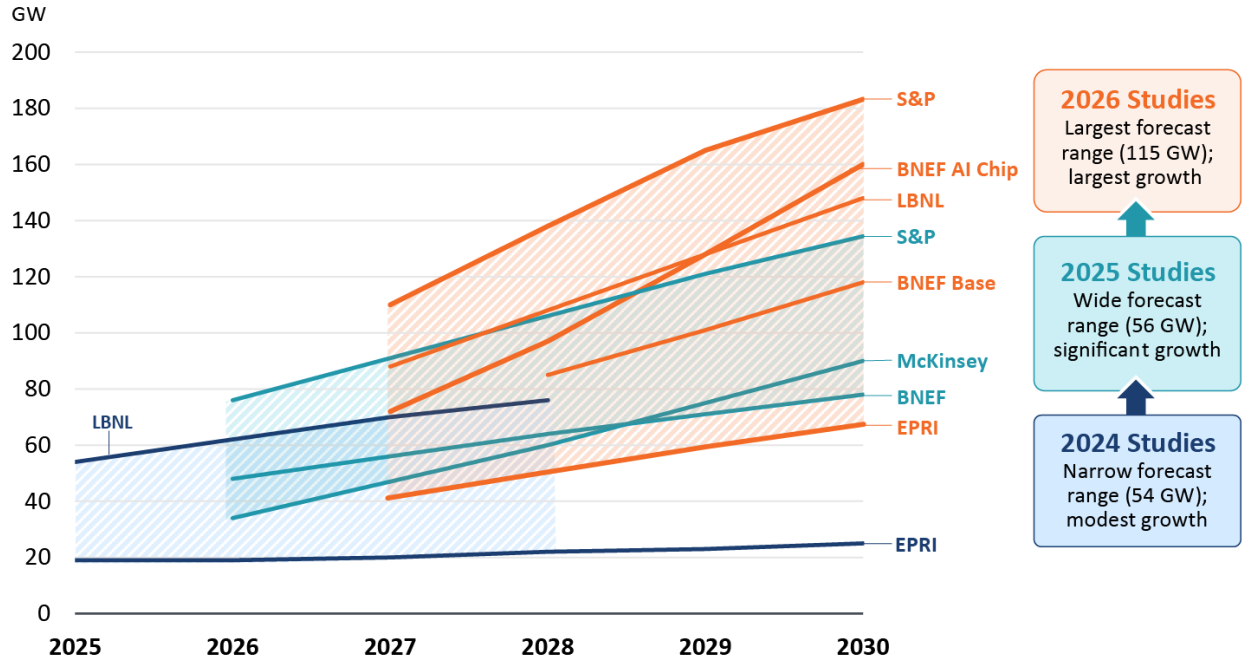
[50] EIA, Electric Power Annual, Table 10.1, 2025

Section 5: A Hedge Against Highly Uncertain Load Growth

System planners face unprecedented uncertainty about future load growth. The prospect of adding multi-gigawatt customers to the grid means some utilities could more than double the size of their systems within the next decade. Because this new demand is concentrated among a small number of customers and the AI sector remains nascent, planners need new measures to mitigate the risk that projected load will not materialize.

The primary challenge is "stranded asset risk." If power system infrastructure is built to serve new customers whose demand does not materialize, existing customers could be left paying for unneeded infrastructure. While the ultimate financial burden will depend on factors such as large load tariff design, contract terms, and enforcement, the potential for investment in assets that are not needed is a fundamental concern.[51] Figure 9 summarizes the wide variation in data center load-growth forecasts, highlighting the uncertainty.

FIGURE 9: UNCERTAINTY IN DATA CENTER LOAD FORECASTS



Sources and Notes: RTO Insider summarizes the studies referenced in the figure: Bloomberg NEF US data center capacity forecast (2026), LBNL United States Data Center Energy Usage Report (2024 and 2025 Update), EPRI Powering Intelligence (2024 and 2025), McKinsey Global Energy Perspective (2026), IEA (2025), S&P (2025 and 2026).

[51] For further discussion of large load tariffs and mechanisms for protecting customers, see LBNL, *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities 2026 Update*, August 2026.



Option Value Through Planning Flexibility

DERs can help mitigate stranded asset risk in two ways.

- **Short development lead times.** Because they face different supply chain constraints, interconnection issues, and development timelines compared to traditional infrastructure, DERs can be deployed with shorter lead times.[52] This shorter lead time reduces forecast uncertainty by allowing planners to respond to load growth closer to real time.
- **Variable cost structures.** Unlike traditional infrastructure, some DERs – particularly demand flexibility – can be scaled back if the load they were intended to serve does not materialize. Performance incentives can be adjusted to reflect the value DERs provide to the system, avoiding payments for unneeded capacity in a way that is generally not possible for long-lived, large-scale resources. Although behavioral considerations may limit dramatic year-to-year changes, periodic adjustments are feasible.

Figure 10 illustrates how these two DER features combine to limit overbuilding of the power system when load does not materialize as expected.

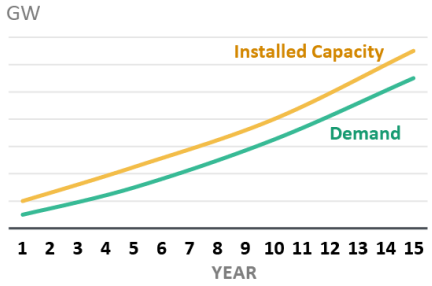
[52] DERs can accelerate the speed to power for large loads by providing capacity for new demand that would otherwise need to wait for traditional supply options to be available. This approach has been coined "Bring Your Own Distributed Capacity (BYODC)." The potential benefits of accelerated load interconnection are not explicitly quantified in this study but are discussed qualitatively below.

FIGURE 10: HOW THE PLANNING FLEXIBILITY OF DERS REDUCES STRANDED ASSET RISK (ILLUSTRATIVE)

CASE 1

Demand Materializes as Expected

Efficient buildout, to meet reliability goals



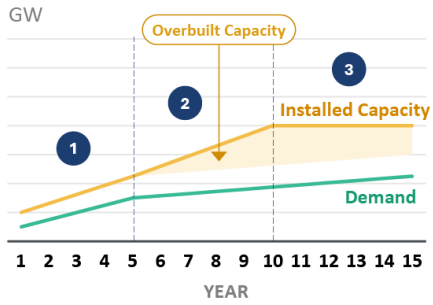
When demand materializes as expected, capacity is built to meet demand plus a planning reserve margin.

In this case, the level of overbuild is efficient; the planning reserve margin exists as a "cushion" to maintain the desired level of reliability across the system.

CASE 2

Demand Lower than Expected | Limited DERs

Significant overbuild due to planning inflexibility

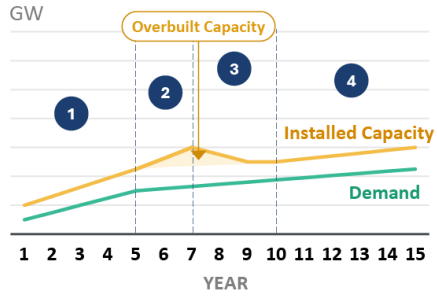


1. In the first five years, load grows as predicted and capacity grows accordingly (no change from Case 1).
2. In year 5, load growth unexpectedly slows. Capacity additions continue according to original trajectory for five years due to long construction lead times of conventional generation.
3. In year 10, new builds stop and capacity remains flat while developers wait for load to catch up.

CASE 3

Demand Lower than Expected | Expanded DERs

Reduced overbuild due to planning flexibility



1. The first five years are the same as Cases 1 and 2.
2. When load growth slows in year 5, DER capacity additions continue for two years but can be paused more quickly than conventional supply. The system is still overbuilt, but not by as much as without DERs (Case 2).
3. DER capacity can be reduced over a few years by dialing back DER performance compensation.
4. Eventually, the system returns to its planning reserve margin and then continues to add supply economically.

A 40% Reduction in Overbuild Costs

Our analysis estimates the value of DER planning flexibility by comparing the overinvestment that would result if load materializes at a significantly lower level than forecast, with and without substantial reliance on DERs in the resource mix.[53]

[53] We develop a "realized load scenario" to assess the impact of load materialization at levels lower than the baseline load forecast. Baseline data center load growth is modeled based on the medium data center growth

Continued on next page

Planning around business-as-usual DER growth leaves system planners without sufficient scalable resources and can produce an expensive, overbuilt system when projected load does not materialize. With only status quo DER deployment in the capacity mix, our analysis estimates that planners would overbuild the system by 153 GW in 2035. Incorporating an expanded DER portfolio into resource planning could reduce that overbuild by roughly 28%, or 43 GW.

That overbuilt capacity is costly. With only status quo DER deployment, the cumulative cost of overbuilding the power system totals roughly $84 billion from 2030 through 2040, the decade following the reduction in load.[54] By contrast, an expanded DER portfolio reduces overbuild costs by $33 billion over the same period.[55] In other words, **greater reliance on DERs in the national power resource mix can reduce the costs associated with overbuilding amid uncertain load growth by roughly 40%.**

System Planning Implications

These findings have important implications for system planning. When the demand outlook is uncertain, flexibility has significant economic value. Rather than planning around a single forecast, utilities and regulators should assess the consequences of underbuilding and overbuilding across a range of plausible outcomes and favor resources, such as DERs, that preserve optionality.

A recent RMI framework for managing uncertain data center demand reinforces this conclusion. It recommends separating committed projects from speculative requests to improve forecasts, refreshing plans more frequently, prioritizing "least-regrets" investments that perform well across multiple futures, staging procurement as customer commitments become firmer, and using tariffs and contracts to place remaining risk on the customers driving it.[56]

DERs are particularly well suited to this approach. Their short lead times, modular scale, and comparatively flexible cost structures allow planners to add capacity incrementally rather than make large, irreversible commitments before demand is known. Paired with scenario analysis and adaptive procurement, DERs can help the power system respond quickly when new load materializes without leaving existing customers to pay for infrastructure when it does not.

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case in EPRI's Powering Intelligence 2026 report. In the realized load scenario, actual data center growth materializes at lower levels based on the AEO 2026 forecast. By 2030, the overstated load forecast is 5% higher than the actual load in that year. See Technical Appendix for more details.

[54] We measure the cost of overbuild as the difference between (1) a scenario that serves the lower load forecast with perfect foresight and (2) a scenario without perfect foresight, in which development lead times cause excess resources to be built for several years before development is adjusted to account for the reduced load forecast. Imperfect load forecasts persist through 2030, after which system planners return to a perfect foresight planning standard. However, traditional generator investments, due to longer lead times, are locked in through 2035, and DER investments, with shorter planning horizons, are only locked in through 2032.

[55] These costs will ultimately be borne by customers, with the class-specific cost burden dependent on factors such as tariff design and no-show clauses, and the enforceability of those clauses.

[56] Jesse Cohen, Drew Beyer, and Lauren Shwisberg, *Planning for Uncertain Data Center Demand*, RMI report, August 6, 2026.



Section 6: Enabling Decarbonization

Although federal decarbonization policy has fluctuated, state policy has maintained a relatively steady focus on reducing power sector carbon dioxide emissions. Around 30 states have adopted clean energy policies aimed at reducing the power system's carbon intensity. Because the power sector accounts for 30% of US carbon dioxide emissions, reducing its emissions is essential to limiting the growing costs of climate change.[57]

However, continued emissions reductions will not necessarily occur on their own. Even if all existing state decarbonization goals are met, our status quo forecast estimates that annual US power sector carbon dioxide emissions in 2050 will be only 30% below today's level, with reductions stalling around 2035. Further progress will require innovation and new, affordable solutions. This section of the report evaluates the decarbonization benefits of DERs.

Reducing Emissions

As discussed in Section 3, an expanded national DER portfolio would avoid roughly 70 GW of natural gas generation – equivalent to 175 power plants – while increasing wind and solar generation. Together, these changes reduce cumulative power sector carbon dioxide emissions by 3% over the study horizon and annual emissions in 2050 by 5%. That amounts to roughly 863 million metric tons over the 25-year study period and 55 million metric tons in 2050 alone. **The cumulative emissions reduction is equivalent to permanently removing 14 million gasoline-powered passenger vehicles from the road**.[58]

Beyond delivering direct environmental benefits through load reductions, flexible DERs can reduce emissions indirectly by mitigating the load impacts of beneficial electrification technologies, such as electric vehicles and heat pumps. By reducing related infrastructure upgrade needs for customers and the power system, flexible DERs can improve the affordability of electrification and accelerate deployment by easing interconnection constraints.

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57 EIA, US Energy-Related Carbon Dioxide Emissions, 2025.

58 US Environmental Protection Agency, Greenhouse Gas Emissions from a Typical Passenger Vehicle (updated June 2026); National Highway Traffic Safety Administration (NHTSA), Vehicle Survivability and Travel Mileage Schedules. Lifetime emissions estimated using 400 grams CO_2 per mile and 152,137 miles of assumed passenger car lifetime travel. Excludes vehicle manufacturing and upstream fuel emissions.

Supporting Affordable Decarbonization

Given currently heightened affordability concerns, controlling costs is critical to continued power sector decarbonization. Although clean energy is increasingly economically competitive with fossil fuel generation, a fully decarbonized power sector will require flexible resources to integrate it reliably. Flexible, dispatchable clean resources that can serve this role – such as long-duration storage, hydrogen, or carbon capture and sequestration (CCS) – remain relatively costly.

The operational flexibility provided by DERs can make a fully decarbonized power sector more affordable. To quantify this value, we analyzed a scenario requiring the power generation fleet to be entirely carbon-free by 2050 and compared outcomes with and without significant reliance on DERs.

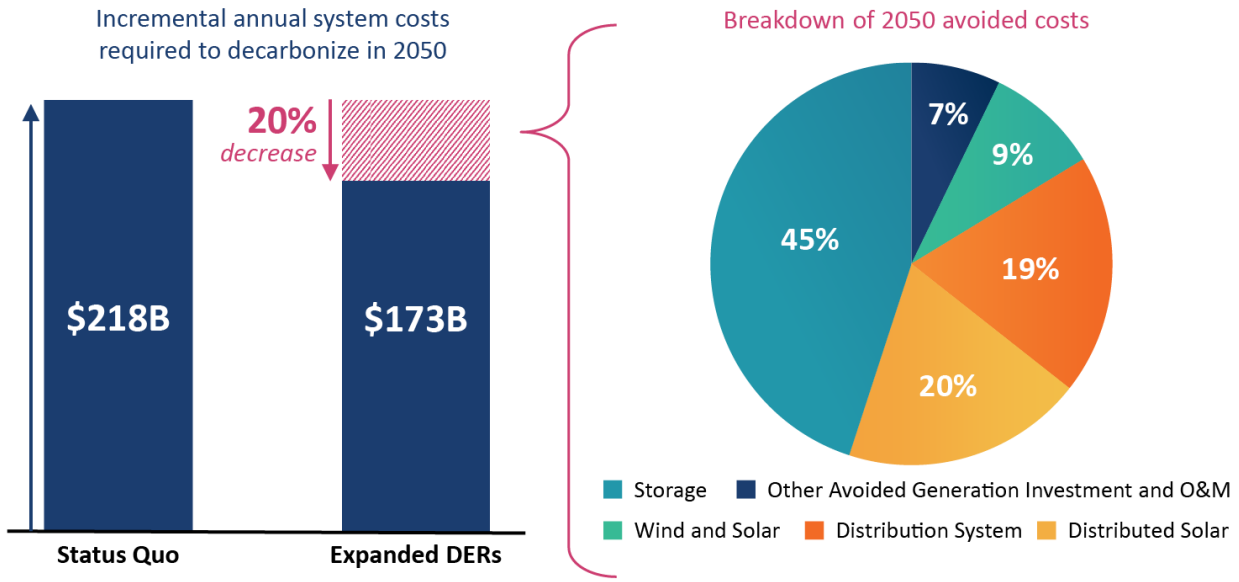
Fully decarbonizing the US power system while meeting load growth will require more than 1,000 GW of additional capacity by 2050, primarily renewables, storage, and clean firm capacity.[59] With an expanded portfolio of DERs, 175 GW (16%) of the needed capacity can be met with low-cost distributed assets.

Without expanded DERs, we estimate that the annual generation cost of full decarbonization – including capital, fixed, and variable costs – would increase by $218 billion by 2050. Expanded DERs lower the annual cost of the fully decarbonized power system by $45 billion, reducing incremental decarbonized power supply costs by nearly 20%.[60] Figure 11 summarizes the reduction in annual 2050 costs from expanded DERs and the savings by category.

[59] Clean firm capacity includes hydrogen combustion turbines, gas with carbon capture and sequestration (CCS), and new nuclear.

[60] Note that the cost savings would not be shared equally between DER participants and non-participants, for the reasons discussed in Section 4 of this report.

FIGURE 11: REDUCTION IN US POWER SECTOR DECARBONIZATION COSTS DUE TO DERS (2050)



A recent study by Lawrence Berkeley National Laboratory (LBNL) and Brattle reinforces these findings through a broader analysis that includes residential and commercial energy efficiency and electrification alongside demand flexibility. Combined with rapid power sector decarbonization, these measures could reduce US building emissions by as much as 91% from 2005 levels by 2050 and generate more than $100 billion in annual power-system savings – enough to offset over one-third of the incremental cost of fully decarbonizing the grid. Although that study's scope and assumptions differ from ours, its results support the same central conclusion: demand-side resources can both reduce emissions and materially lower the systemwide cost of achieving a carbon-free power sector.[61]

[61] Jared Langevin et al., "Demand-Side Solutions in the US Building Sector Could Achieve Deep Emissions Reductions and Avoid Over $100 Billion in Power Sector Costs," *One Earth* 6, no. 8 (2023): 1005–1031.



Section 7: Moving from Potential to Results

There are a variety of pathways for addressing barriers to DER deployment and enabling the level of adoption assumed in this study. New policy interventions, market design decisions, regulatory initiatives, business models, planning practices, technological innovations, and advancements in consumer engagement all could play a role in unlocking an expanded national portfolio of DERs.

Given the breadth of the pathways, and likely variation in their relative attractiveness across jurisdictions, the results presented in prior sections of this report did not assume or prescribe specific approaches taken to unlock DER benefits. We modeled achievement of an ambitious but feasible end-state if addressable barriers are removed.

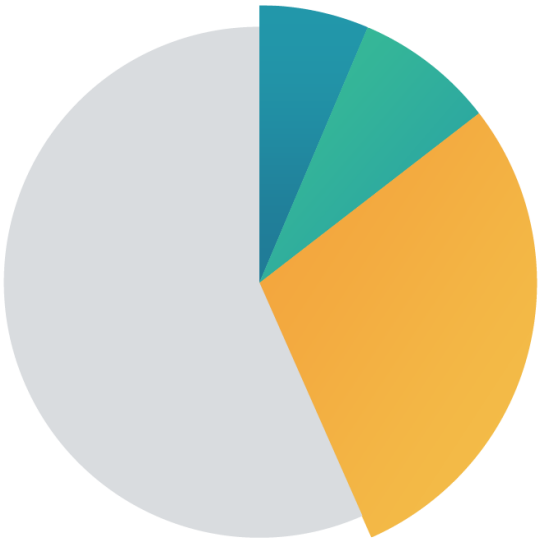
To provide a tangible illustration of the potential impact of targeted action, this concluding section of the report examines three reforms: integrating DERs into distribution planning, automating and streamlining DER interconnection, and reforming DER permitting.[62]

Together, we estimate that these three initiatives could unlock 43% of the cumulative national DER benefits identified in this study. They are not a complete policy agenda, nor the only way to enable DER value. Still, the scale of the opportunity available from these three reforms makes them clear near-term priorities for policymakers, regulators, utilities, and industry stakeholders to consider.

Figure 12 summarizes the contribution of each of the three initiatives. Their relative impact is discussed in the remainder of this section of the report.

[62] These are three of several initiatives proposed in Pew's Policy Playbook. The initiatives were selected due to a combination of their expected impact, interrelated nature, and alignment with our quantitative modeling framework.

FIGURE 12: CONTRIBUTION OF THREE POLICY INITIATIVES TO NATIONAL DER BENEFITS



Interconnection Reform | $39B, 6% of total

- Would accelerate connections while giving utilities tools to manage constraints
- Flexible interconnection agreements and "dynamic operating envelopes" can allow DERs to export within limits that reflect local grid conditions

Permitting Reform | $50B, 9% of total

- Behind-the-meter (BTM) solar & storage permitting is fragmented, duplicative, and costly
- Streamlining the process could reduce permitting costs by 90% (achieved in Australia and Germany)

Distribution System Value | $177B, 29% of total

- Utilities must be able to forecast their availability, communicate dispatch needs, verify performance, and compensate for dependable local capacity
- Requires DER deployment where constraints are expected, aggregated at sufficient scale, and incorporated into utility planning, procurement, and operations

Other Reforms | $347B, 57% of total

Additional progress needed to modernize utility regulation, develop more effective approaches to consumer engagement, and create clearer, more consistent pathways for DERs to capture the full value they provide (among others)

Enabling Distribution System Value

Most distribution planning processes still – at best – treat DERs as changes in forecasted demand rather than as controllable resources that can address specific grid needs. Planning methods were largely developed before widespread DER adoption, and many utilities do not yet have the data, operational visibility, or control systems needed to rely on customer-sited resources as alternatives to conventional infrastructure.

Unlocking this value requires DERs to be deployed where constraints are expected, aggregated at sufficient scale, and incorporated into utility planning, procurement, and operations. Utilities must be able to forecast their availability, communicate dispatch needs, verify performance, and compensate customers or aggregators for delivering dependable local capacity. Operating DERs in accordance with grid constraints is also essential to ensure that coordinated charging or exports do not create problems elsewhere on the system.

Our analysis estimates the savings available when these capabilities enable DERs to defer distribution capacity investments that would otherwise be needed. As described in Section 2, we account for resource-specific operating constraints and limit the estimated opportunity to load-driven upgrades that can realistically be deferred by reducing local peak demand. This approach captures a meaningful but targeted share of distribution investment without assuming that DERs can replace all conventional upgrades.

This initiative would produce $177 billion in cumulative cost savings through 2050, roughly 29% of the total DER value estimated in this study.[63]

Lowering Costs Through Local Permitting Reform

Permitting for BTM solar and storage remains fragmented, duplicative, and costly in many US jurisdictions. Requirements that vary by local authority, manual application and inspection processes, and uncertain timelines add expense without changing the underlying technology. Permit Power estimates that permitting accounts for 18% of residential solar "soft costs" and 14% of total installed costs, increasing customer prices and slowing deployment.[64]

Australia demonstrates what a simpler pathway can enable. Roughly one in three Australian homes has rooftop solar, supported by national equipment, installer standards, and streamlined local approval pathways for ordinary rooftop systems. Accredited installers typically coordinate registration, grid-connection requirements, and eligibility for federal certificates, reducing the time and administrative burden for customers.[65]

Our analysis estimates the benefits of reducing US solar permitting costs by approximately 90%, consistent with levels achieved in markets such as Germany and Australia. We assume that distributed solar compensation continues to provide customers with a reasonable investment payback; as administrative costs fall, less ratepayer-funded compensation would be needed to support the same level of adoption. Lower distributed solar costs therefore enable more financially sustainable compensation policies that share savings across all customers.

This initiative would produce $50 billion in cumulative cost savings through 2050, roughly 9% of the total DER value estimated in this study.

Expanding DER Output Through Interconnection Reform

Interconnection processes designed for one-way power flows can delay the interconnection of distributed resources and restrict their operation once connected. Batteries and bidirectional EVs may be permitted to offset a customer's own consumption but prohibited from exporting electricity, preventing otherwise available capacity from serving the broader grid. Without reform, up to 75% of

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63 A portion of total distribution savings is unlocked through interconnection policy initiatives. We removed those savings from the distribution policy results to avoid double-counting value streams.

64 Permit Power, *As Cheap as Our Peers: How cutting red tape can lower the cost of rooftop solar and offset rising utility bills*, October 2025.

65 Australian Government Department of Climate Change, Energy, the Environment and Water, Federal Solar Consumer Guide, accessed October 4, 2026; Australian Government Clean Energy Regulator, Small-Scale Renewable Energy Scheme, September 2026.

new distributed storage and bidirectional charging capacity could remain subject to these export constraints.[66]

Reform can unlock this stranded capability without requiring the grid to accommodate unrestricted exports at all times. Flexible interconnection agreements and "dynamic operating envelopes" can allow DERs to export within limits that reflect local grid conditions, accelerating connections while providing utilities with tools to manage constraints.

Our analysis estimates the system value of removing inflexible export restrictions and enabling participating DERs to provide their full available capacity to the grid.[67] By 2050, enabling DER exports would avoid 3 GW of additional gas capacity and shift 12 GW of storage capacity to the grid edge by making distributed batteries, bidirectional EVs, and other flexible resources available when the system needs them. Together, these effects produce $39 billion in cumulative cost savings through 2050, roughly 6% of the total DER value estimated in this study.

Conclusion

The US will need a broad portfolio of resources to meet growing electricity demand while maintaining affordability, reliability, and progress toward decarbonization. The findings of this study suggest that DERs should be a much larger part of that portfolio.

When policy and market innovation remove barriers to deployment, DERs can become a resource of utility-scale significance. DERs can reduce the need for conventional generation and distribution investment, mitigate rising customer bills, facilitate decarbonization, and address risks associated with uncertain load growth.

The breadth of these benefits is the advantage of diversifying the US energy resource portfolio with DERs. Resources located at the grid edge can provide value across multiple levels of the power system while also benefiting participating customers directly.

DERs also provide valuable optionality. Their relatively short lead times and modularity allow deployment to respond more readily to emerging system needs. This flexibility is increasingly important as the magnitude and location of future load growth become more uncertain.

The implication for decision-makers is that DERs warrant treatment as a core power system resource, not a pilot project or a resource of last resort. Achieving this objective requires moving from a system that largely accommodates DERs to one that plans for and uses them as a resource. At sufficient scale, policies that unlock DER deployment are investments in a reliable, lower-cost, cleaner power system.

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[66] Based on a review of current utility programs and interconnection policies, approximately 25% of customers have access to programs that would compensate for full exports back to the grid. We assume that share remains the same through the modeling horizon without the impacts of interconnection reform.

[67] Additionally, interconnection reform can contribute to reducing soft costs. Our analysis captures those benefits under permitting reform.

EXTENDING THE RESEARCH

The findings of this study establish a strong foundation for additional analysis and implementation tools. The following opportunities could help decision-makers translate the study's national and regional insights into more tailored policies and programs.

State-level potential. State-specific estimates of DER potential could give state policymakers and regulators a more granular basis for setting targets and designing policies that reflect local conditions.

Data center partnerships. Hyperscalers could help accelerate DER deployment through "bring your own distributed capacity" models. A practical roadmap could support consistent, equitable implementation.

Utility-specific distribution value. Targeted utility analyses could build on the study's national estimates by identifying local opportunities, the investments needed to enable them, and key implementation considerations.

Deployment models. Customer value and the pace of DER deployment will vary across deployment models. Further analysis could assess the relative impacts of various business models and regulatory structures.

Customer participation. Streamlined enrollment and other behavioral strategies can be as important as, or more important than, financial incentives to drive adoption. A program design checklist could help regulators and utilities apply proven practices that encourage adoption and sustained participation.

Wholesale market opportunities. Quantifying the resource adequacy value of DERs in wholesale electricity markets could identify additional revenue to support program administration and customer incentives, helping to scale deployment.

Appendix: Regional Insights

Although this report presents findings at the national level, regional analysis highlights additional considerations that vary with customer composition, generation mix, load characteristics, and other factors. To illustrate these regional nuances, this appendix compares results for two regions: the Intermountain West and MISO.

Spotlight: Intermountain West

The Intermountain West (New Mexico, Arizona, Nevada, Utah, and portions of Colorado and Idaho) is projected to experience roughly a doubling of peak load by 2050 and is among the fastest-growing regions in the country. Meeting this demand growth will require a broad resource mix that includes utility-scale renewables and storage, new and existing gas generation, and increased imports. By 2050, we project that utility-scale wind and solar will supply roughly 30% of the region's electricity. Our analysis shows that DERs can be a valuable tool to integrate these renewable additions into a reliable regional energy portfolio.

Despite this growth, the region begins with relatively limited demand response capability, equivalent to 1.6% of generation capacity, compared with a national average of 3.1%. Distributed solar currently dominates the regional DER portfolio, reflecting the Intermountain West's strong solar resource, while other DERs remain comparatively underdeveloped.

Removing barriers to DER deployment unlocks substantial growth across a broader portfolio of flexible resources. Expanded commercial and industrial demand response, managed EV charging, HVAC load control, and distribution-connected storage increase the region's dispatchable DER capacity to approximately 10% of total installed capacity by 2050, slightly above the projected national average of 9%. Distribution-connected storage is particularly valuable because it can absorb abundant daytime solar generation and discharge that energy during higher-value evening hours.

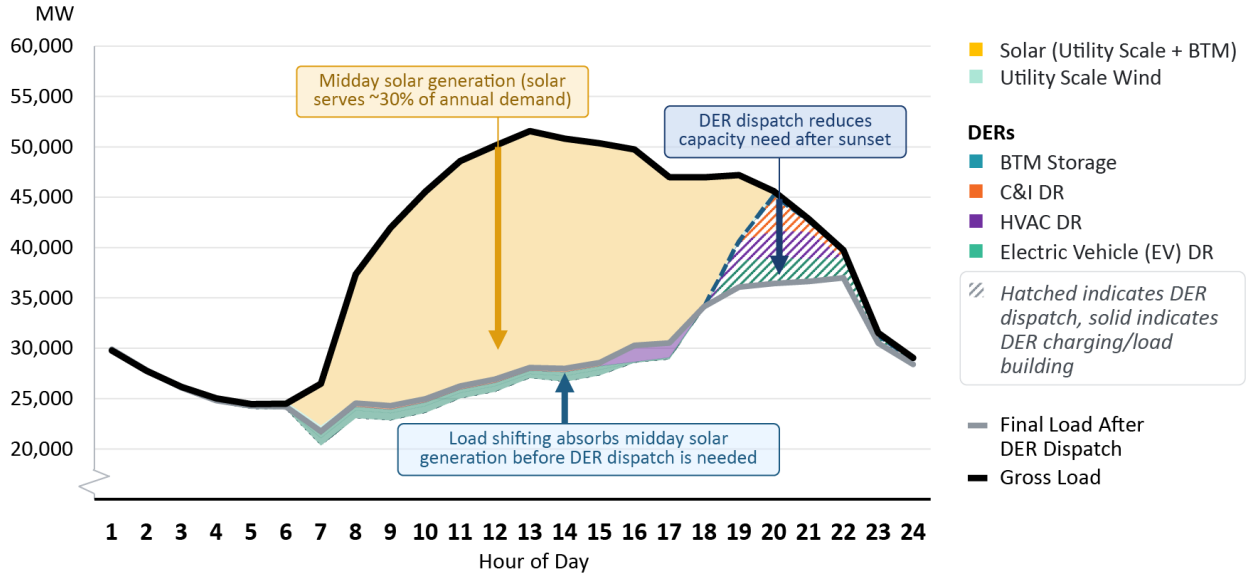
As solar grows to serve roughly 30% of regional electricity demand by 2050, flexible DERs become increasingly important for managing the evening transition as solar output declines. Dispatchable DERs displace 9 GW of gas capacity by 2050 and help balance midday solar generation. DERs accelerate renewable development, enabling 8 GW (roughly 20%) more utility-scale solar, along with a modest increase in wind capacity, by 2050.

Deploying DERs to facilitate renewable integration reduces annual emissions in the Intermountain West by 14% in 2050 (12 MMT of carbon dioxide). Removing barriers to DER deployment could also avoid $2 billion in annual generation and distribution system investment, and $22 billion in cumulative avoided costs, by 2050.[68]

[68] Note that the avoided costs do not account for DER operational costs or performance payments. Savings would not be shared equally between DER participants and non-participants, for the reasons discussed in Section 4 of this report.

Figure 13 illustrates how DERs can be dispatched to provide value to the Intermountain West's bulk system.

FIGURE 13: EXAMPLE DER DISPATCH FOR INTERMOUNTAIN WEST (SUMMER PEAK DAY, 2050)



Spotlight: MISO

Looking ahead, we project that both resource economics and utility emissions-reduction targets will drive a substantial shift in the generation mix in the Midcontinent ISO (MISO) region. Even without additional state policy mandates, renewables – primarily wind – will supply roughly 60% of regional electricity demand by 2050.

At the same time, recent high-capacity market prices signal an emerging need for dependable new capacity. Pending MISO market reforms could materially affect how DERs are accredited and compensated, shaping their ability to help meet this need.

The MISO region also begins with an uneven DER baseline. Northern MISO states have well-established residential HVAC and commercial and industrial demand-response programs, with participation levels that exceed those in most regions; programs in Central and Southern MISO remain less developed.

Removing deployment barriers narrows this gap in DER deployment across MISO states. Established programs in northern states continue to expand, while less mature programs in Central and Southern MISO scale much more rapidly. By 2050, addressing DER barriers could increase DER capacity roughly threefold in northern MISO states such as Minnesota and Michigan and more than sixfold in central and southern MISO states such as Louisiana, Missouri, and Indiana, compared with today's levels.[69]

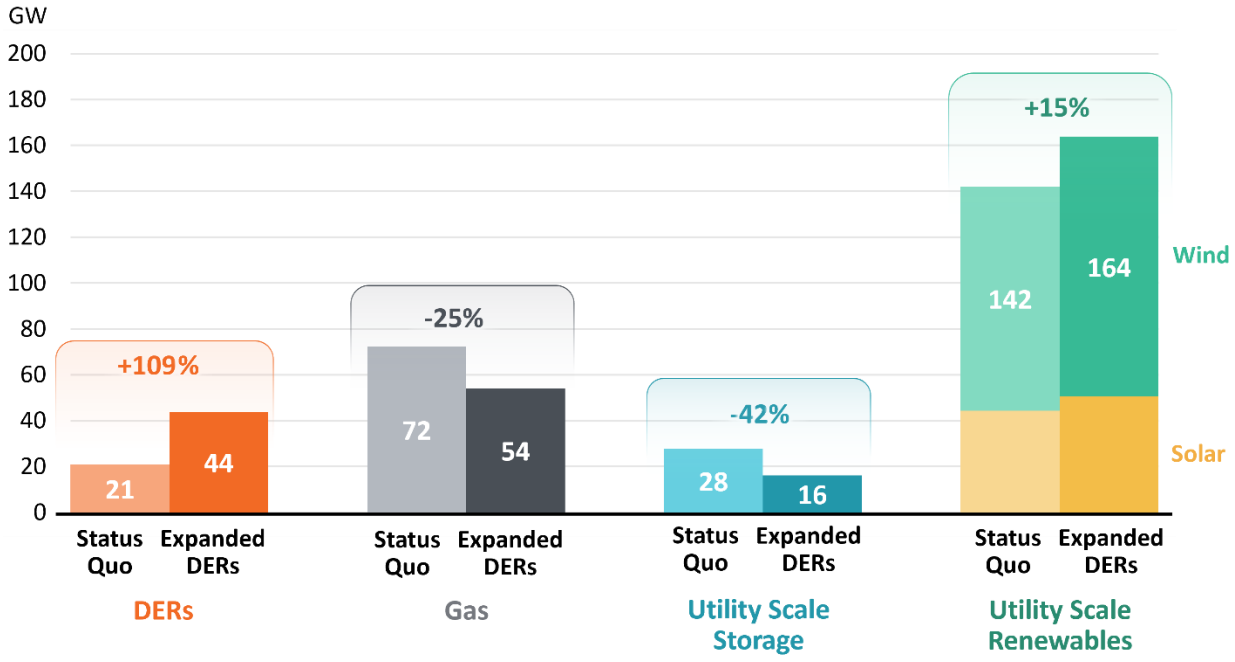
[69] DER penetration is reported based on nameplate capacity.

This expanded portfolio avoids approximately 18 GW of gas capacity and shifts 12 GW of centralized storage to the grid edge. Together, these changes are equivalent to roughly 45% of net capacity additions and facilitate additional renewable integration. Removing barriers to DER deployment reduces MISO carbon emissions by 25 MMT in 2050 (a 14% reduction in annual emissions) and avoids $4 billion in generation and distribution system investment that year, resulting in $43 billion cumulative avoided costs from 2026–2050.[70]

The value of these resources is not confined to the summer peak. Load growth and the changing generation mix produce tighter resource adequacy conditions in both summer and winter, increasing the importance of DER portfolios that can perform reliably throughout the year.

Figure 14 summarizes the change in capacity additions attributable to an expanded DER portfolio.

FIGURE 14: MISO NAMEPLATE CAPACITY ADDITIONS (2026–2050)



[70] Note that the avoided costs do not account for DER operational costs or performance payments. Savings would not be shared equally between DER participants and non-participants, for the reasons discussed in Section 4 of this report.

FURTHER READING

The following selected resources provide additional analysis of the planning, affordability, flexibility, decarbonization, and policy themes explored in this report.

Authoring Organization(s)	Report	Purpose and key finding
The Brattle Group	***The Affordability Advantage* (2026)**	Finds that scaling residential VPPs through innovative customer engagement can reduce system costs, could offset projected household bill increases, and deliver $4–$7 billion in additional annual consumer benefits if scaled nationally.
The Brattle Group	***The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability* (2026)**	Finds that better use of existing grid capacity and flexible demand could save more than $100 billion over the next decade and moderate rate pressure.
The Brattle Group	***Real Reliability: The Value of Virtual Power* (2023)**	Finds residential virtual power plants can provide reliable capacity at a cost that is 40%–60% lower than competing resources.
The Brattle Group	***The National Potential for Load Flexibility: Value and Market Potential Through 2030* (2019)**	Estimates cost-effective load flexibility potential amounts to 200 GW nationally and could deliver more than $15 billion in annual benefits by 2030, led by automated, connected programs.
LBNL / The Brattle Group and coauthors	***Demand-Side Solutions in the US Building Sector Could Achieve Deep Emissions Reductions and Avoid Over $100 Billion in Power Sector Costs* (2023)**	Shows that electrification, efficiency, and demand flexibility can jointly decarbonize buildings while lowering system costs and managing peaks.
The Pew Charitable Trusts	***Distributed Energy Can Unleash the Resilient, Affordable Grid of the Future* (2026)**	Policy playbook for integrating DERs into planning and procurement, reforming permitting and interconnection, and strengthening resilience.
RMI	***Planning for Uncertain Data Center Demand* (2026)**	Offers a risk-management framework for uncertain data-center load, using better forecasts, portfolios, staged procurement, and risk allocation to limit overbuild.
RMI	***Power Shift: How Virtual Power Plants Unlock Cleaner, More Affordable Electricity Systems* (2024)**	Finds that fully integrating virtual power plants into planning and operations can reduce system costs by 20% and emissions by 7%, avoid 75% of new gas units, and enable 200 MW of additional renewables in a representative power system.
RMI	***Virtual Power Plants, Real Benefits* (2023)**	Estimates virtual power plants could cut peak demand by 60 GW and annual power-sector spending by $17 billion by 2030, while outlining barriers to scale.
US DOE / LBNL / The Brattle Group	***A National Roadmap for Grid-Interactive Efficient Buildings* (2021)**	Roadmap to triple building efficiency and demand flexibility by 2030, with $100–$200 billion in estimated system savings over two decades.
US Department of Energy	***Pathways to Commercial Liftoff: Virtual Power Plants — 2025 Update* (2025)**	Charts a path to 80–160 GW of virtual power plant capacity by 2030 and identifies actions needed across the market.
Vibrant Clean Energy	***Why Local Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid* (2020)**	Models a more distributed US grid and finds that scaling local solar and storage can lower total system costs while improving resilience.

FOR FURTHER INFORMATION



Ryan Hledik

Principal,
San Francisco

Ryan Hledik focuses his consulting practice on regulatory, planning, and strategy matters related to emerging energy technologies and policies. His work on the grid edge has been cited in federal and state regulatory decisions, as well as by major media outlets such as *CNN*, *Forbes*, *National Geographic*, *The New York Times*, *NPR*, *PBS*, and *The Washington Post*. He has published more than 30 articles on electricity matters, presented at industry events in 11 countries, and given lectures on distributed grid economics at Penn, Stanford, and Yale.

Ryan is a founding Alumni Policy Advisor for the Kleinman Center for Energy Policy at the University of Pennsylvania and is an Advisory Committee member for Pew's DER Policy Initiative. He received his MS in Management Science and Engineering from Stanford University and his BS in Applied Science from the University of Pennsylvania.

Ryan.Hledik@brattle.com



Kate Peters

Energy Associate,
San Francisco

Kate Peters focuses on strategic planning and regulatory issues related to an increasingly decarbonized electric power system. She has supported utilities, renewable developers, research organizations, and technology companies in matters related to resource planning, capacity expansion modeling, electrification grid-impact studies, and the emerging role of virtual power plants (VPPs) in decarbonized markets.

Kate has contributed to high-profile studies assessing the economic viability of distributed energy resources, modeling the grid impacts of electrification, and evaluating the role of demand flexibility in mitigating peak load growth. Her recent consulting experience includes estimating the cost-effective potential for grid flexibility in New York, assessing the market opportunity for VPP deployment in California, and modeling electrification scenarios to inform climate policy decisions in Maryland. Kate received her BA in Environmental Economics from Middlebury College.

Kate.Peters@brattle.com

ABOUT BRATTLE

The Brattle Group is a premier global consulting firm specializing in economics and finance. With more than 550 professionals across North America, Europe, and Asia-Pacific, and a distinguished network of leading academics and industry experts, we bring analytical rigor, credibility, and clarity to complex challenges. For decades, clients have trusted Brattle for independent analysis in litigation, energy and financial markets, and regulatory and strategic advisory settings.

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