The National Case for a More Distributed Power Grid

New Evidence on Affordability and Demand Growth

VOLUME II: TECHNICAL APPENDIX

PREPARED BY

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

PREPARED FOR

The Pew Charitable Trusts

November 2026



Brattle

Pew

NOTICE

This report was prepared by The Brattle Group for The Pew Charitable Trusts. It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

Copyright © 2026 The Brattle Group, Inc.

TABLE OF CONTENTS

1. Introduction 4

2. Model Overview 5
   a. gridSIM 6
   b. FLEX 6

3. Modeling the US Electric Grid (Core Scenario) 7
   a. Load Forecast 8
   b. Supply Chain Constraints 11
   c. Generator Costs 12
   d. State Clean Energy Policies 14
   e. Summary of All Inputs 15

4. Distribution System Value 18

5. Modeling DERs 19
   a. Modeled DERs 20
   b. Status Quo DER Forecast 21
      i. HVAC, Water Heating, EV, and C&I DR 21
      ii. Distributed PV 22
      iii. Distributed Storage 22
   c. Expanded DER Forecast 23
      i. HVAC, Water Heating, EV, and C&I DR 23
      ii. Distributed PV 26
      iii. Distributed Storage 26
   d. Characterizing DER Operations 27

6. Alternative Scenario 1: Overbuild Risk 27

7. Alternative Scenario 2: Full Decarbonization 31

8. Policy Scenarios 32
   a. Distribution Value 32
   b. Interconnection Reform 32
      i. Distributed Storage 32
      ii. EV V2G 33
   c. Permitting Reform 33

1. Introduction

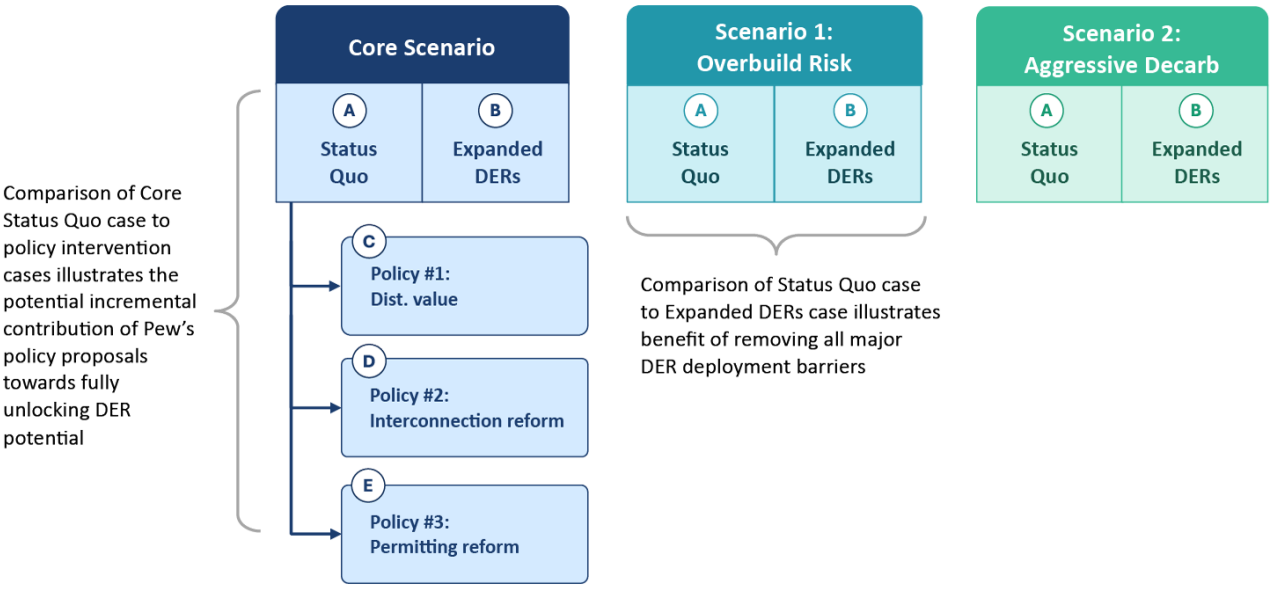
This study quantified the national value of addressing DER deployment barriers through 2050. We describe the findings of the study in our Volume I Report. This Volume II Technical Appendix provides further detail on the modeling approach and assumptions underlying the analysis.

We evaluated the benefits of deploying DERs in an Expanded DER case that addressed key barriers relative to a case where current barriers preventing large-scale deployment persist (Status Quo DERs). Those benefits include shifting utility-scale capacity to the grid edge, facilitating emissions reductions, and improving affordability. We analyzed the benefits under a core scenario that forecasts the US grid based on current outlooks and policies plus two alternate sensitivities. The first examines the benefits DERs provide when planning for uncertain load growth, and the second evaluates the benefits of DERs when transitioning to a fully decarbonized power sector.

Further, facilitating DER deployment will require action from all levels, including policy reform. We quantify the isolated impacts of three policies in deploying DERs in our Core Scenario: enabling integration in distribution planning, reforming interconnection, and facilitating permitting. The scenario design is illustrated in Figure 1.

The following sections summarize our modeling methodology and input assumptions. Section 2 provides an overview of the FLEX and gridSIM models. Section 3 summarizes key supply-side modeling assumptions for the Core scenario. Section 4 summarizes our approach to distribution benefit modeling. Section 5 summarizes DER assumptions, including forecasted technology adoption, participation rates, and operational parameters. Sections 6 and 7 provide an overview of the two alternate scenarios, Overbuild Risk and Full Decarbonization. Finally, Section 8 summarizes underlying assumptions for the three policy cases.

FIGURE 1: SCENARIO DESIGN



2. Model Overview

The analysis combines two complementary perspectives: a bottom-up estimate of the bulk power system, using Brattle's capacity-planning model (gridSIM), and a top-down view of distribution-system opportunities. Brattle's FLEX model supports the characterization of DER operating capability that feeds into this system-wide analysis.

Recent applications of this modeling framework include New York's Grid Flexibility Potential Study, GridLab's California virtual power plant assessment, and Brattle's analysis of the impact of federal clean energy tax credits. The framework has also supported national work on virtual power plants and grid-interactive efficient buildings for the US Department of Energy, an assessment of residential virtual power plant reliability for Google, and US building-sector decarbonization scenarios developed with Berkeley Lab, among other studies.[1]

[1] The Brattle Group, *New York's Grid Flexibility Potential*, January 2025; The Brattle Group, *California's Virtual Power Potential*, April 2024; The Brattle Group, *Economic Analysis of Clean Energy Tax Credits*, February 2025; The Brattle Group and LBNL, *A National Roadmap for Grid-Interactive Efficient Buildings*; The Brattle Group, *Real Reliability: The Value of Virtual Power*, April 2023; The Brattle Group and LBNL, *Demand-Side Solutions in the US Building Sector*, September 2023.

a. gridSIM

We use gridSIM to simulate the future US electric grid with and without the impact of DER-enabling policies. The model optimizes capacity expansion and system dispatch to meet hourly demand, capacity requirements, and clean energy policies while respecting additional modeled constraints. It minimizes the net present value of system costs over a multi-decade time horizon. gridSIM simulates hourly market operations, investment, and retirement, and was designed from the bottom up to analyze how key drivers of the decarbonized grid of the future will affect future market outcomes.

gridSIM is particularly well suited to understanding the challenges of high levels of renewable integration and the implications of clean energy and carbon policies of various designs by dynamically capturing the declining marginal capacity value of dispatchable and nondispatchable resources.

b. FLEX

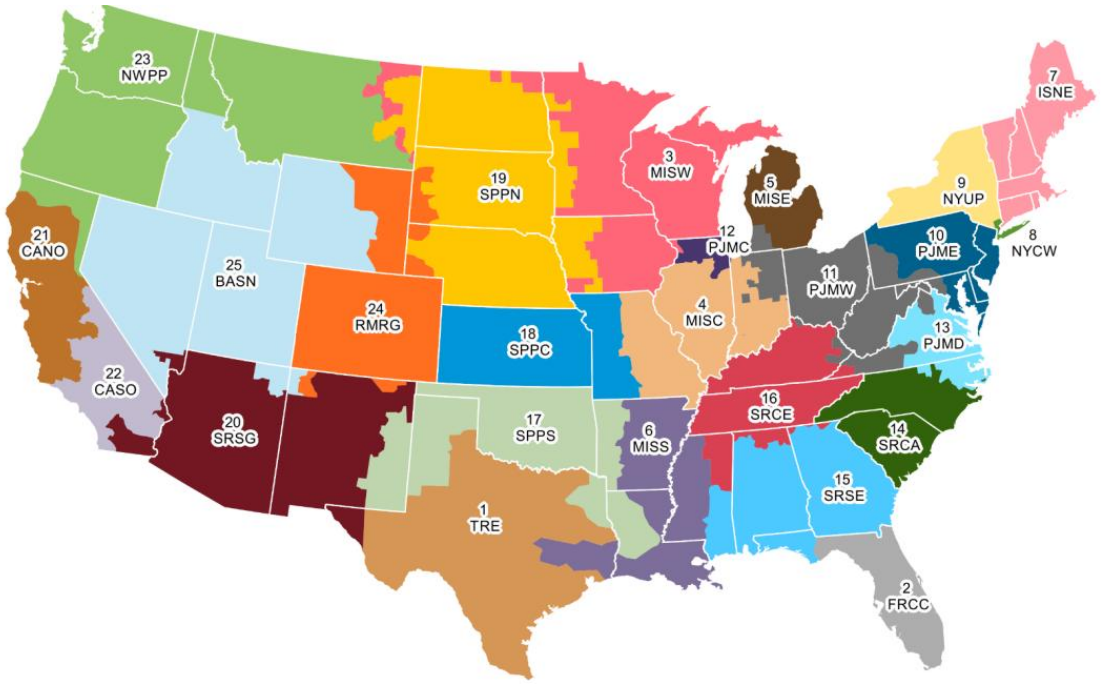
The Brattle Group's FLEX model was developed to quantify the potential impacts, costs, and benefits of demand response (DR) programs. We integrate the fundamentals of the FLEX model into our modeling of DER deployment within gridSIM.

The FLEX modeling approach offers the functionality to accurately estimate the broader range of benefits that are being offered by emerging flexibility programs, which not only reduce system peak demand, but also provide around-the-clock load management opportunities. The FLEX modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the US and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs.

3. Modeling the US Electric Grid (Core Scenario)

We modeled 25 zones that align with the same geographic definition in the US Energy Information Administration (EIA)'s *Annual Energy Outlook (AEO),* as shown in Figure 2.[2] Our modeling horizon goes through 2050, beginning in 2025, with 5-year increments.

FIGURE 2: MODEL REGIONS



Source: Reproduced from EIA's *Annual Energy Outlook*, April 2026.

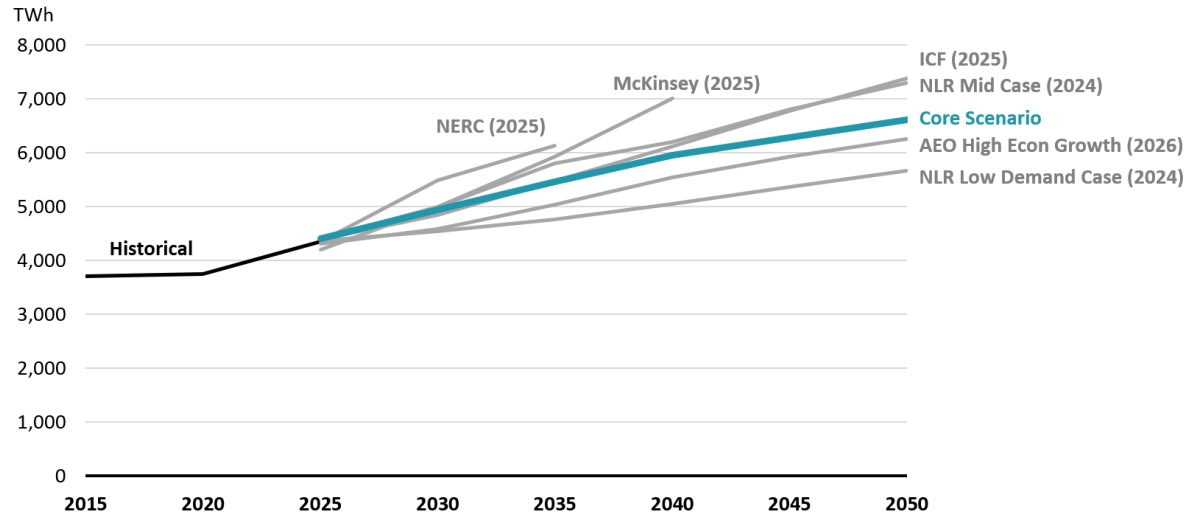
Our Core Scenario represents a likely forecast of the future US grid based on current outlooks of demand, supply, and policy mandates. Several inputs used to characterize the supply-side system have a significant influence on DER model outcomes and/or have particularly uncertain trajectories due to current market conditions. We carefully developed those key inputs, including load forecast, supply chain constraints, costs of new generation, and clean energy policies, with review from our study's technical advisory committee. A full overview of all supply-side inputs is included at the end of the section, with the key inputs discussed in the detailed subsections below.

[2] US EIA, *Annual Energy Outlook (AEO)*, April 2026.

a. Load Forecast

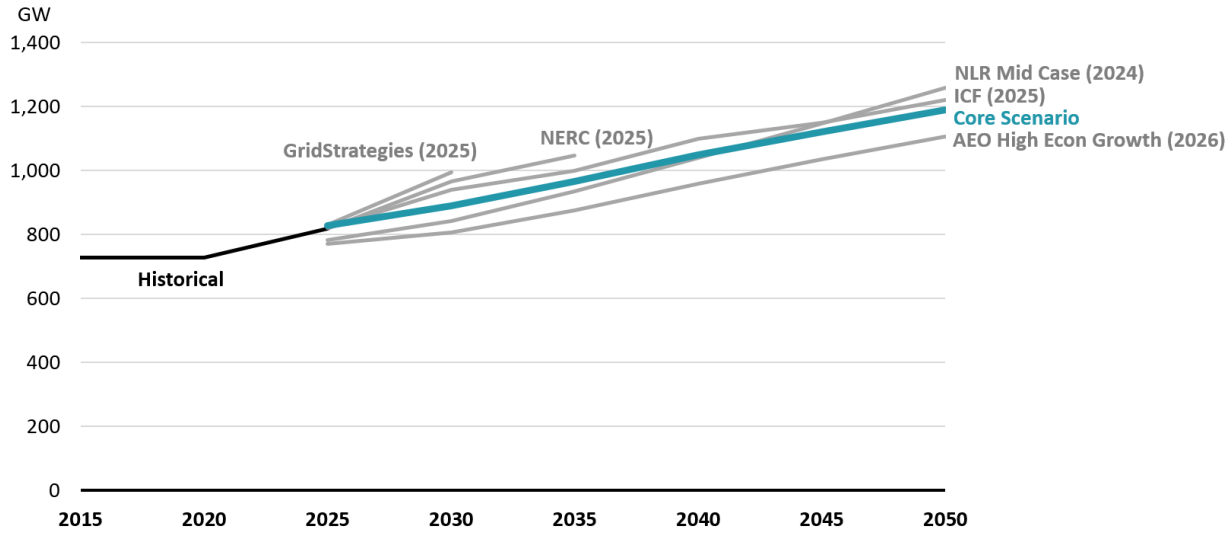
The Core Scenario load forecast is based on the 2026 EIA AEO's "High Economic Growth" case, adjusted to reflect near-term data center load growth projected by EPRI. We selected the AEO "High Economic Growth" case and applied additional adjustments based on benchmarking to other national load forecast reports and electrification studies. Figure 3 and Figure 4 below illustrate how the resulting US energy and peak demand forecasts used in our study compare to other projections.

FIGURE 3: US ENERGY DEMAND FORECAST



Sources: NERC, Electricity Supply & Demand, 2024; McKinsey, "Powering a new era of US energy demand," 2025; National Laboratory of the Rockies (NLR), Cambium, 2024; ICF, *Electricity demand growth*, 2025; EIA, *AEO*, 2026.

FIGURE 4: PEAK DEMAND FORECAST

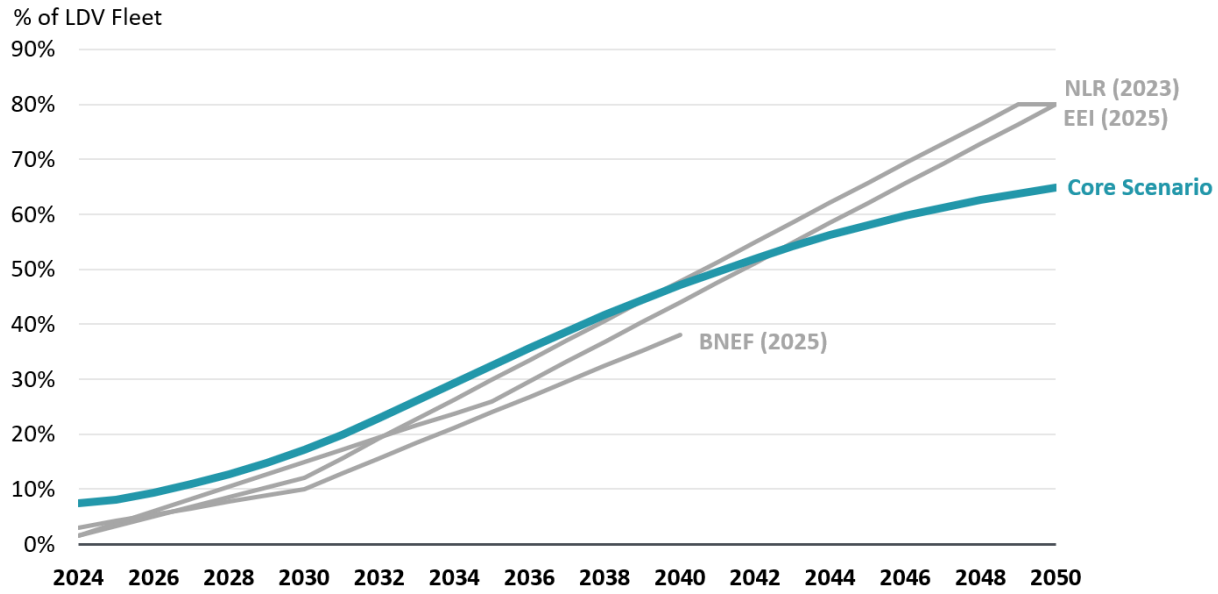


Sources: NERC, Electricity Supply & Demand, 2024; NLR, Cambium, 2024; ICF, *Electricity demand growth*, 2025; Grid Strategies, *Load Growth Forecast Reports*, 2025; EIA, *AEO*, 2026.

Our Core Scenario forecast falls between other public outlooks of US demand and provides the end-use granularity needed for modeling DER deployment levels consistent with underlying demand. Within our load forecast is embedded demand from transportation and building sectors – end-uses that can provide significant flexibility if enrolled in programs. Figure 5 below illustrates how transportation electrification compares to other sources.[3] We additionally benchmark building electrification levels, which are not shown.

[3] Regional EV forecasts are consistent with state- and ISO-level forecasts. For example, we confirmed that *AEO*'s EV LDV forecast for the Middle Atlantic region is consistent with Con Edison's projections for the New York region. *AEO*'s New England EV forecast is aligned with ISO-NE. Similar checks were also conducted for other regions, including California.

FIGURE 5: EV PENETRATION FORECAST (% OF LDV FLEET)



Sources and Notes: EEI, 2024; NLR, *The 2030 National Charging Network: Estimating US Light-Duty Demand for Electric Vehicle Charging Infrastructure*, 2023; BNEF, *Electric Vehicle Forecast*, 2025. The NLR and EEI projections reach ~80% of electric stock by 2050 due to outdated assumptions about federal policy support.

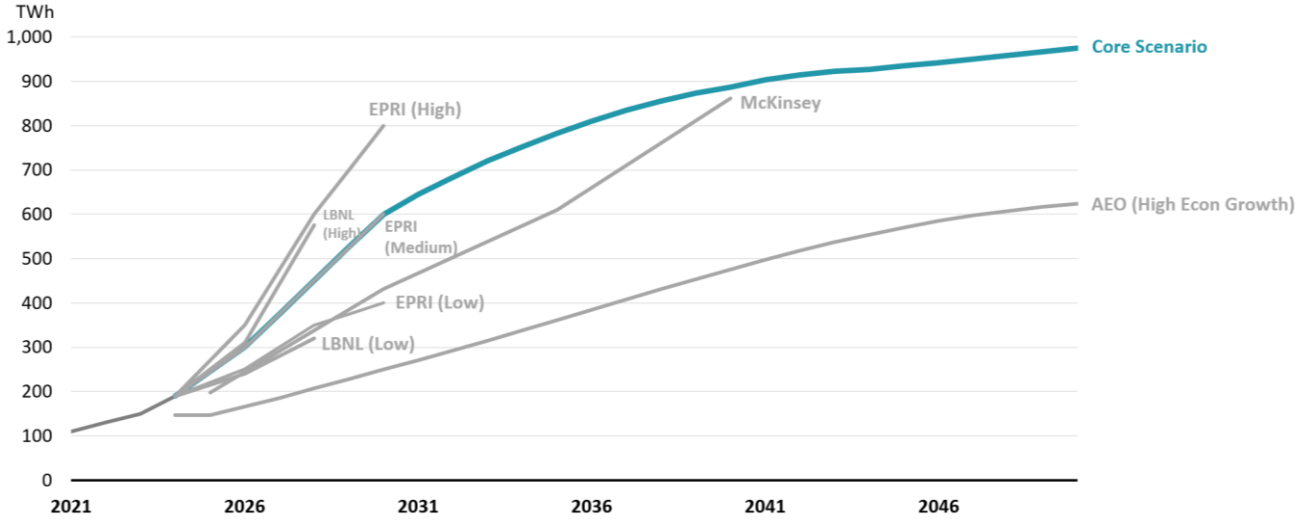
Data center demand is also embedded in our demand forecast, based on EPRI's Medium Growth Case, and will increase significantly to comprise 12% of demand by 2050. Our data center load growth forecast aligns with industry expectations set by other sources such as EPRI, the Lawrence Berkeley National Laboratory (LBNL), and McKinsey, although data center demand outlooks are constantly evolving.[4] EPRI's analysis captures recent data center capacity announcements, as of the time of publication, and project development status, with discounts that reflect uncertainty at various stages of development.[5]

EPRI's Medium Growth Case projects data center demand through 2030. Given the lack of credible data center load growth projections beyond that timeframe, we adopted the AEO's post-2030 load growth rate through 2050 (with some smoothing in the years following 2030). Figure 6 situates our data center load growth forecast against other sources.

[4] The *AEO* models data center servers as an end use, rather than a distinct building type, within EIA's Commercial Demand Module. AEO data center demand projections are based on a 2013 study and a 2021 update to the study completed by Guidehouse, Inc. and Leidos, Inc. Due to AEO's reliance on older studies, energy projections for data center demand reach around 250 TWh in 2030 compared to 400-800 TWh across other studies.

[5] The Medium Growth case includes all data center projects under construction, 75% of those in advanced planning, and 10% in early planning as fully operational by 2030.

FIGURE 6: DATA CENTER ENERGY DEMAND FORECAST



Sources: EPRI, *Powering Intelligence 2026*; LBNL, *United States Data Center Energy Usage Report*, 2024; McKinsey, "Powering a new era of US energy demand," 2025; EIA, *AEO*, 2026.

b. Supply Chain Constraints

Supply chain constraints will limit the ability of capacity additions to match load growth in the near term, with gas turbine capacity being the prominent example. To capture this dynamic within our model, we established annual maximum build limits by generator type, based on a review of historical build rates by region, interconnection queue analysis, announced manufacturing expansion plans, and recent industry reports on generation equipment availability. Additionally, cumulative build limits for wind and solar are informed by GIS land use analysis of the National Laboratory of the Rockies (NLR)'s geospatial dataset and The Nature Conservancy's *Power of Place* data.[6]

Annual gas build limits from 2026-2030 are limited to 18 GW/year (90 GW total) based on our review of planned announcements from Velocity Suite.[7] From 2030-2035, supply chain constraints are relaxed slightly to reflect expanded manufacturing capability, consistent with our review of recent manufacturing announcements that project gas turbine manufacturing capability to roughly double by 2028. Accordingly, we assumed the limit on annual gas generator additions in the US can be no greater than 2x the historical capacity addition rate

[6] NLR, Wind Supply Curves and Solar Supply Curves, May 2026; The Nature Conservancy, *Power of Place: National Technical Briefing*, May 2023.

[7] Velocity Suite's database includes EIA Electric Power Monthly, FERC & other federal regulatory data, ISO interconnection queue data, regional data, as well as Hitachi Energy primary research.

between 2030–2035 (i.e., maximum capacity additions of 36 GW/yr, compared to a historical average addition rate of 18 GW per year).[8] We developed similar maximum deployment estimates for storage (4x the historical build rate), solar (3x the historical build rate), and wind (2x the historical build rate) to reflect reasonable interconnection queue and supply chain capabilities in the near term (from 2026–2030). After 2030, renewable deployments are restricted by land-use constraints.

We also allowed gas retrofits to carbon capture and storage (CCS) and coal-to-gas conversions as compliance options to meet EPA 111 emissions regulations. We restrict coal-to-gas conversions based on existing unit age, assuming units with remaining lifetimes less than 45 years would be candidates for retrofit.[9] An additional 10% derate is applied to account for site-specific constraints not represented in the model, such as natural gas pipeline costs. For CCS retrofits (gas only), we limited total US additions to 20 GW based on EPA modeling.[10] This limit is relaxed to 80 GW in the Full Decarbonization scenario to reflect additional pressures that encourage investment in low-carbon resources.[11]

c. Generator Costs

Inflation, increased demand, and supply chain constraints have driven significant increases in the cost of power generation equipment in the past few years. Capital, fixed, and variable cost projections for new generators by resource type are adjusted from NLR's 2024 *Annual Technology Baseline* (the most recent *ATB* at the time), with modifications to account for recent cost increases based on a Brattle report for PJM and interconnection cost increases based on an LBNL study.[12] Capital costs include interconnection expenses from LBNL that vary by resource

---

8 The historical capacity additions rate was developed from review of Velocity Suite data. We reviewed the following manufacturing expansion plans: GE plans to expand capability from 12 GW in 2025 to 24 GW by 2028. Siemens plans to expand capability from 6 GW in 2025 to 13 GW by 2028. Mitsubishi plans to expand capability from 12 GW in 2025 to 37 GW in 2028.

9 EPA's Integrated Planning Model (IPM) found that the average age of coal units that retired between 2000 to 2022 was 53 years, and units with 2 to 9 years of remaining life could support 40% gas co-firing. To support full conversion, we assume at least 8 remaining years will be needed.

10 EPA's IPM projects around 20 GW of CCS.

11 Many studies find higher penetration of CCS under a net-zero requirement. EPRI's *Power Decarbonization* study builds around 90 GW of gas with CCS by 2050 in their Net-Zero scenario; Princeton's *Net-Zero America* study builds 60 GW by 2050 in the High Electrification scenario.

12 The Brattle Group, *Sixth Review of PJM's Variable Resource Requirement Curve*, April 2025; LBNL, Interconnection Costs in the PJM Territory, January 2023; The Brattle Group, *2026 ERCOT CONE Study*, October 2026.

type. Regional multipliers from EIA modeling are included to account for geographic variation in costs across our 25 regions.

All new resources can be economically selected in the model starting in 2030, except for small nuclear, which can be built starting in 2035, and hydrogen combustion turbines (CTs) in the 2040 model year. We select small nuclear, hydrogen CTs, and gas with carbon capture as representative of clean-firm resources that the US would need to achieve deep decarbonization goals. Additional technologies such as long-duration energy storage and advanced geothermal, among others, may play a role in the future grid and should be included in detailed decarbonization modeling, but were excluded from this study to focus on the impacts of DERs. Capital costs for modeled resources are shown in Table 1.

TABLE 1: NEW RESOURCE CAPITAL COSTS ($2026/KW)[13]

Resource	2030	2050
Natural Gas Combined Cycle (CC)	$2,718[14]	$1,351
Natural Gas Combustion Turbine (CT)	$1,560	$1,250
Natural Gas Steam Turbine (ST)	$4,739	$3,754
Coal-to-Gas Retrofit	$225	$180
Nuclear	$8,212	$5,097
Nuclear (Small Modular Reactor)	$10,405	$4,967
Solar	$1,389	$805
Storage (2-hr)	$1,088	$778
Storage (4-hr)	$1,676	$1,137
Storage (8-hr)	$2,852	$1,855
Wind (Offshore)	$5,600	$3,539
Wind (Onshore)	$1,547	$1,166
Natural Gas CC w/ Carbon Capture and Storage (CCS)	$3,930	$2,024
Hydrogen CT	$1,950	$1,563

d. State Clean Energy Policies

State clean energy policies will influence the generation buildout mix by region. We modeled achievement of all existing statutory carbon emissions goals, renewable portfolio standards (RPS), clean energy standards (CES), and resource procurement goals.[15] We have also included utility targets when more aggressive than state goals in certain regions. We assumed that distributed solar is eligible to meet RPS and CES targets, although the specific contribution criteria may vary by state. Table 2 summarizes the modeled state clean energy policies.

[13] We do not model new coal deployments, but attribute ongoing costs to existing assets.

[14] NG CC capital costs for 2030 are increased to reflect near-term supply chain constraints based on review of sources including *Utility Dive*, GE Vernova, Envernus, GridLab, and close collaboration with the study's technical advisory committee. 2030 costs land at the upper end of benchmarks given the high demand and inflationary environment that is forecasted to persist in the near-term. Costs return to the adjusted NLR ATB values gradually over the 2030 to 2040 period (supported by WoodMac).

[15] Established from a review of publications from LBNL, the Center for Climate and Energy Solutions (C2ES), Clean Energy States Alliance, RTO/ISO reports, and publicly available state statutes and energy agency publications.

TABLE 2: MODELED STATE CLEAN ENERGY POLICIES

State	RPS & Clean Energy Targets	GHG Policy	Procurement Targets
CA	60% renewable by 2030; 100% clean by 2045	85% reduction by 2045	N/A
CO	92% clean by 2050	80% reduction by 2030; net-zero by 2050	N/A
CT	100% carbon-free by 2040	Net-zero by 2050	2 GW offshore wind by 2030
DE	40% renewable by 2035	Net-zero by 2050	N/A
IL	40% renewable by 2030; 100% clean by 2050	N/A	N/A
ME	80% renewable by 2030; 100% clean by 2040	80% reduction by 2050	3 GW offshore wind by 2040
MD	50% renewable by 2030	Net-zero by 2045	8.5 GW offshore wind by 2031
MA	44% renewable by 2030; 100% clean by 2050	Net-zero by 2050	5.6 GW offshore wind by 2027
MI	60% renewable by 2035; 100% clean by 2040	Net-zero by 2050	N/A
MN	55% renewable by 2035, 100% clean by 2040	Net-zero by 2050	N/A
NC	N/A	Net-zero by 2050	N/A
NV	50% renewable by 2030, 100% clean by 2050	Net-zero by 2050	N/A
NJ	50% renewable by 2030	80% reduction by 2050	11 GW offshore wind by 2040, 2 GW storage by 2030
NM	80% renewable by 2050	N/A	N/A
NY	70% renewable by 2030; 100% clean by 2040	Net-zero by 2040	9 GW offshore wind by 2035, 3 GW storage by 2030
OR	100% clean by 2040	Net-zero by 2045	N/A
RI	100% renewable by 2033	Net-zero by 2050	1 GW offshore wind by 2035
VA	81% renewable by 2050, 100% clean by 2050	Net-zero by 2045	5.2 GW offshore wind by 2035, 16.1 GW solar + onshore wind by 2035, 3.1 GW storage by 2035
VT	100% renewable by 2035	80% reduction by 2050	N/A
WA	100% clean by 2045	95% reduction by 2050	N/A

e. Summary of All Inputs

Table 3 summarizes all supply-side modeling inputs used to characterize the power system in the Core Scenario. Key inputs are described in more detail in the sections above.

TABLE 3: SUMMARY OF SUPPLY-SIDE MODELING INPUTS

Transmission	
Transmission Limits	Existing and projected transmission limits between regions are developed from EIA National Energy Modeling System (NEMS) inputs.
Internal/External Transfers	Flows between US regions are optimized within the model; external transfers (e.g., with Canada and Mexico) are modeled based on historical data.
Load	
Load Forecast	*Key input - see discussion above.*
Hourly Load Shapes	Hourly system load shapes are based on 2023 historical hourly system load data and adjusted in future years based on the NLR Cambium Mid-Case for magnitude and electrification. Profiles are scaled to forecasted peak and energy values.
Generation Resources	
Supply Chain Constraints	*Key input - see discussion above.*
New Resource Costs	*Key input - see discussion above.*
Characterization of Existing Generators	Existing unit capacities and heat rates by region are developed based on EIA NEMS. Fuel emissions factors are from EPA's GHG Emissions Factor Hub.
Near-term Additions/Retirements	Near-term additions and retirements are based on EIA NEMS plant-level data and supplemented by EIA 860 to reflect additional near-term gas additions not included in NEMS.
Renewable Generation Profiles	Hourly renewable generation profiles for all zones are based on historical generation data from Renewables.ninja. Monthly hydropower and nuclear availability by region from EIA Electric Power Report historical generation data.
Thermal Outages	Hourly forced thermal outages are based on Brattle analysis establishing historical relationship between temperature and outage rate. Maintenance outage schedules are based on SPP's average monthly planned outage shape (2006–2020) with regional adjustments based on NERC's Winter and Summer Reliability Assessments.
Fuel Prices	Natural gas prices are developed using 2023 Henry Hub daily gas prices, S&P Global 2025 monthly average gas prices for Henry Hub and all EMM gas fuel

	zones, and 2030 Henry Hub future monthly prices.[16] Daily Henry Hub prices are adjusted to each EMM gas zone using 2025 monthly basis differentials, then escalated to 2025 and 2030 price levels based on Henry Hub price growth. Beyond 2030, gas price growth is developed from EIA AEO. Annual biomass, oil, and coal prices are from *AEO*, and nuclear prices are based on NLR's *Annual Technology Baseline* (*ATB*).
Ancillary Services and Real-Time Market Revenues	Since we do not explicitly model ancillary services, we adjusted capital costs for gas and storage resources to reflect additional non-modeled value streams (including real-time market arbitrage) to create realistic investment comparisons against other resources. We established adjustments based on internal dispatch modeling of $18/kW-yr, $20/kW-yr, and $40/kW-yr for gas CC, gas CT, and storage units, respectively. These adjustments decline by 2050 (to 25% of their real value) to account for market saturation that dilutes ancillary services prices and arbitrage opportunities.
Policy Assumptions	
Tax Credits	Investment Tax Credits (ITC) equal to 30% of installation cost are modeled for solar, offshore wind, and battery storage, and Production Tax Credits (PTC) of $0.03/kWh are modeled for land-based wind. Solar and wind credits are available to resources placed in service before 2028, while nuclear and battery storage credits are phased out between 2034–2036, in line with recent legislation.[17] State support for renewables (e.g., RECs) is modeled through state clean energy and RPS targets.
State Clean Energy/Emissions	*Key input - see discussion above.*
EPA 111	Compliance with EPA 111 emissions requirements is modeled due to enforcement at the time of this study. This includes retirement or conversion of existing coal capacity to gas by 2035 (assuming that CCS retrofits for coal will not be adopted at scale). Capacity factor limits of 40% for baseload gas capacity and 20% for peakers are also enforced beginning in 2035. Note, both policy deadlines are set to 2032 but enforced beginning in first applicable model year (e.g., 2035).

[16] Henry Hub historical prices and forecasts come from NYMEX, June 2026.

[17] Solar and wind projects must begin construction before July 5, 2026, or be placed in service before January 1, 2028, to be eligible to receive tax credits. There is a four-year safe harbor if construction begins before July 5, 2026, and the project is completed by the end of 2030, but additional ownership and FEOC provisions apply. Given these limitations, tax credits for wind and solar in gridSIM are modeled for resources online by 2030.

Capacity Market/ELCC	Regional capacity requirements are set by forecasted peak load and planning reserve margins that vary by region. Resource capacity ratings vary with deployment levels and are determined dynamically by the model based on hourly contributions of the resources to peak hours. This endogenous calculation of the ELCC values captures the declining marginal value of renewables and duration-limited resources (e.g., storage, DR) at higher penetrations.

4. Distribution System Value

DERs can provide distribution system value based on their ability to defer load-growth-driven distribution capacity investments, when integrated in distribution planning. DERs located near load can reduce local peak demand and delay the need for upgrades to distribution infrastructure. However, only a subset of distribution capital expenditures is driven by load growth, and not all of these investments can be deferred through DER deployment.

Our capacity expansion model, gridSIM, does not include detailed distribution network modeling for the US. We developed a national forecast of the distribution deferral opportunity that DERs could provide based on historical investment data, forecasted load growth, and DER operational characteristics. The key steps and data inputs are described in Table 4.

TABLE 4: DER DISTRIBUTION DEFERRAL VALUE APPROACH

Analytical Step	Details
Quantify historical distribution investments by modeled region	Using historical utility distribution investment data available from FERC Form 1, we established the historical US distribution investment from 2010–2025 ($0.76 trillion in inflation-adjusted, non-discounted dollars, grossed up to account for missing utilities in the FERC Form 1 data).[18] Data is available at the distribution utility level, which we aggregated to our 25 modeled regions.
Establish share of distribution investment driven by load-growth	Roughly 30% of distribution capex is for load-growth-driven capacity expansion needs.[19] DERs that reduce local peak demands could slow the rate of spending. Other distribution costs unrelated to load growth could include replacing aging infrastructure, hardening the grid for extreme weather events, and improving IT systems, among many other things that are generally not addressable by DERs and are not considered to be a DER value stream in this analysis.
Forecast future distribution investments	We extrapolate historical distribution growth-driven investments to future years in proportion to modeled load growth for each region over the 2026–2050 modeling horizon.
Restrict distribution investment deferral opportunity based on feasible DER operations	Among the growth-driven upgrade needs, 60% may have characteristics that would allow them to be deferred with DERs.[20] Those characteristics could include, for example, hours of overload that are addressable within DER dispatch constraints, or the portion of distribution investment located in areas with sufficient local DER capacity.
Evaluate distribution deferral value based on DER deployment	The resulting portion of distribution investments established thus far are considered eligible for deferral if DERs are deployed in sufficient quantity, at locations of need, and with required operational characteristics. We evaluate the portion of system investment that DERs can mitigate based on our modeled Expanded DER deployment forecast, which is up to 90%. 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. In the analysis, we assume an average deferral period of 5 years. That value results in the deferral value of 5 years of distribution investment carrying charges that would otherwise be included in annual revenue requirements.

5. Modeling DERs

We model two DER deployment scenarios. Status Quo represents a deployment forecast anchored on historical trends, with current barriers persisting to limit full DER potential. The

Expanded DER Case accounts for DER deployment once barriers are addressed to facilitate integration into grid planning. Forecasts are anchored on industry trends, experience from leading jurisdictions, and other relevant sources to serve as inputs to the capacity expansion modeling.

a. Modeled DERs

Table 5 below summarizes the DER options offered by customer class included in the study. We note that energy efficiency (EE) is not included as a DER program type, but a base level of EE is embedded in the load forecast. Large load/data center DR is not explicitly modeled.

TABLE 5: MODELED DER TECHNOLOGIES

Technology	Residential	C&I
Distributed PV	✓	✓
BTM battery storage	✓	✓
FTM battery storage	✓	✓
Cooling DR	✓	*Modeled as*
Space heating DR	✓	*Auto/manual DR*
Water heating DR	✓	X
EV managed charging DR	✓*(LDV)*	✓*(MHDV)*
EV vehicle-to-grid (V2G)	✓*(LDV)*	✓*(School bus only)*
Auto/manual DR	X	✓

[18] 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.

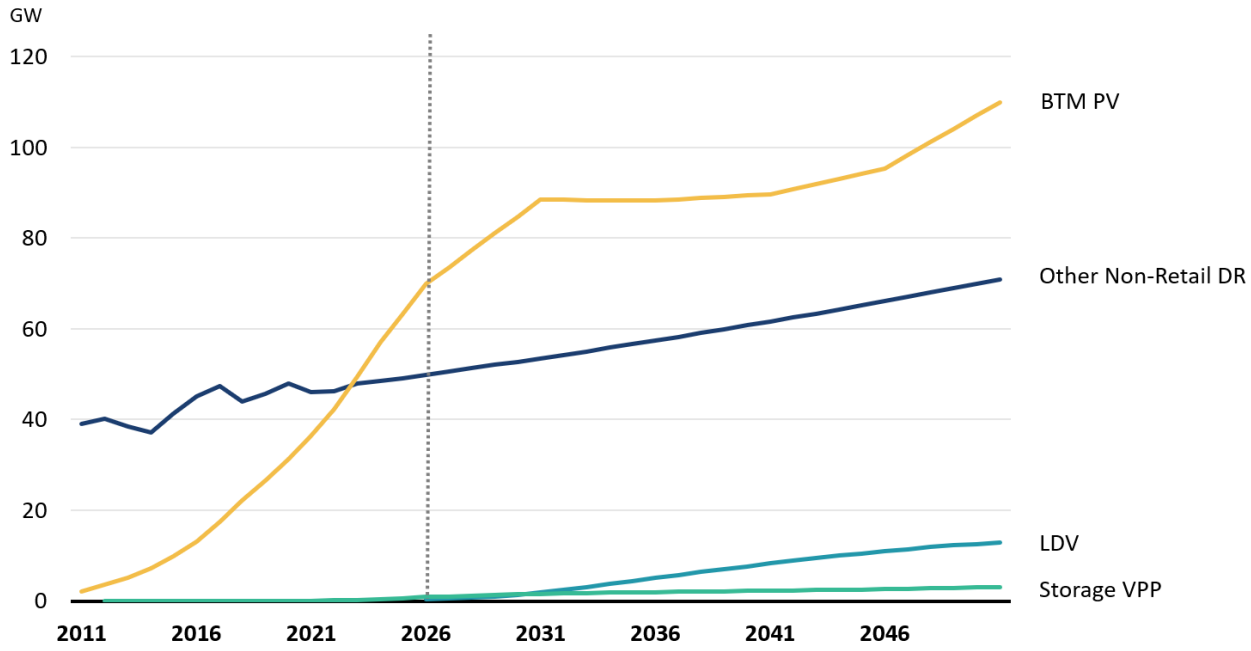
[19] LBNL, *Electric Utility Distribution Costs*, May 2026.

[20] This haircut 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.

b. Status Quo DER Forecast

Figure 7 shows the trajectory of each DER type in the Status Quo case. The sub-sections below describe key assumptions for each DER type.

FIGURE 7: STATUS QUO DER TRAJECTORY



Note: Capacity is reported in ICAP GW. The lines are mutually exclusive and sum to 298 GW by 2050.

i. HVAC, Water Heating, EV, and C&I DR

The Status Quo DER forecast assumes that future DER deployment will be limited by existing barriers. To establish the Status Quo trajectory for cooling DR, heating DR, water heating DR, and auto/manual DR, we extrapolated existing DR capability based on average historic DR growth rates from 2010–2024 (1.5%/year for Residential DR, 1.4%/year for C&I DR).[21] Incremental growth in EV managed charging is added to account for future electric light-duty vehicle (LDV) adoption (consistent with *AEO*) and 10% enrollment in managed programs by 2050.[22] LDV vehicle-to-grid (V2G) and medium- and heavy-duty vehicle (MHDV) programs are

[21] EIA, Form EIA-861, 2025; FERC, *Reports on Demand Response and Advanced Metering*.

[22] Nationwide, participation rates in most EV managed charging programs have not exceeded 10-20% enrollment (SEPA). Con Edison reported 25.9% enrollment in SmartCharge NY amongst residential EV owners at the end of 2024 (Con Edison, Distributed System Implementation Plan, 2025). While other benchmarks include DTE Electric's Smart Charge Program with approx. 7.3% enrollment (DTE Electric, Transportation Electrification Plan, 2026, pp. 8 and 64), Puget Sound Energy's Flex EV program with approx. 7% (PSE, RFP for DSM, 2025), and

Continued on next page

not included in the Status Quo scenario based on limited commercial viability under existing policy and regulatory barriers.

ii. Distributed PV

The distributed photovoltaic (PV) forecast was developed based on the *AEO* 2026 High Economic Growth case and supplemented by state-specific forecasting for California from the CEC (high scenario).[23] Distributed solar includes residential BTM, commercial BTM, and front-of-meter (FTM) installations, like community solar. Residential solar costs in the Status Quo scenario begin at $3.75/W in 2026 and decline through 2050 based on NLR ATB's Moderate cost trajectory for residential solar.[24] Commercial and community solar costs are taken directly from NLR ATB's Moderate scenario cost trajectory for commercial solar.

iii. Distributed Storage

We explicitly model the subset of distributed storage capacity expected to be enrolled in controllable demand response or VPP programs. Additional BTM capacity is deployed but does not provide comparable grid services unless controlled through a utility, aggregator, or other program.

The BTM storage forecast was developed from the BTM PV forecast based on average PV-to-storage sizing ratios and historical stock attachment rates, applied separately for residential and commercial customers.[25] For California, the BTM storage forecast was taken from the CEC directly (high scenario). We assume that 11% of BTM storage will participate in demand response by 2050 based on a review of today's average residential storage participation rates. Limited FTM storage is deployed in the Status Quo case, due to the continuation of current barriers. We assume 5% of new utility-scale additions will be located in front of the customer meter in the Status Quo deployments. Battery specifications vary by customer segment, all with dispatch capabilities up to four hours.

BGE's target for its Smart Charge Management program of approx. 10% by the end of 2027 (MD PSC, Electric System Planning, 2025).

[23] California Energy Commission, Behind-the-Meter Distributed Generation Forecast Results, October 2025.

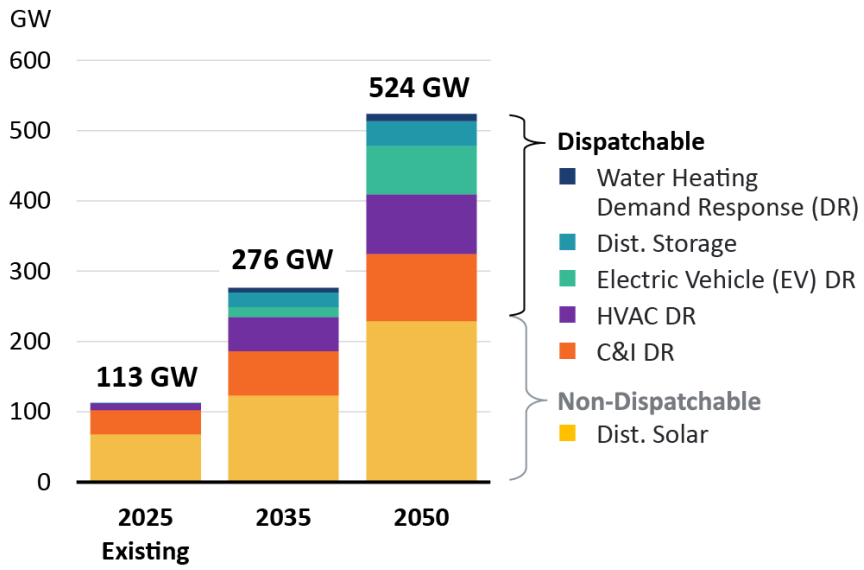
[24] We establish 2025 costs based on several sources, including Permit Power and SEIA.

[25] We assumed that the size of BTM storage units averages 75% of the associated BTM PV system based on LBNL. The assumed stock attachment rate was 8% for residential systems and 7% for commercial and community systems, also from LBNL.

c. Expanded DER Forecast

Figure 8 shows the trajectory of each DER type in the Expanded DERs case. The sub-sections below describe key assumptions for each DER type. DER deployment in the Expanded DERs case is developed to reflect realistic achievable deployment if barriers are removed. Participation rates are supported by levels achieved in leading programs today.

FIGURE 8: EXPANDED DER TRAJECTORY



i. HVAC, Water Heating, EV, and C&I DR

Table 6 summarizes customer electrification adoption assumptions for model years 2030 and 2050. Technology adoption determines eligibility to enroll in controllable DER programs.

TABLE 6: EXPANDED DER TECHNOLOGY ADOPTION

Program	Segment	Eligibility	
		2030	2050
LDV Managed Charging	Residential	17% of fleet	65% of fleet [26]
MHDV Managed Charging	C&I	2% of fleet	24% of fleet [27]
LDV V2G	Residential	17% of fleet	65% of fleet
MHDV V2G	C&I	0.04 M buses	0.25 M buses [28]
Water Heating	Residential	48% of residential customers	50% of residential customers [29]
Auto/manual DR	C&I	14 GW	22 GW [30]
Cooling DR	Residential	77% of residential customers	83% of residential customers [31]
Heating DR	Residential	35% of residential customers	38% of residential customers [32]

Table 7 summarizes program impact and participation assumptions for model years 2030 and 2050. Participation is expressed out of the eligible customers summarized in the above table.

[26] Customers with an EV LDV based on regional stock count forecasts from *AEO 2026*, consistent with load forecast. Also applies in 2030.

[27] ZEV freight truck saturation from *AEO 2026*. Also applies in 2030.

[28] National-level counts of electric school bus fleet from *AEO 2026* allocated based on EMM region share of EV LDV fleet. We only model MHDV V2G for school buses due to heterogeneous driving constraints for other MHDV types that prevent a realistic modeled representation.

[29] Customers with electric water heating based on regional stock count forecasts from *AEO 2026*. Also applies in 2030.

[30] Peak demand for all C&I customers based on *AEO 2026* and excluding data centers. Also applies in 2030.

[31] Customers with central air conditioning based on regional stock count forecasts from *AEO 2026*. Also applies in 2030.

[32] Customers with space heating based on regional stock count forecasts from *AEO 2026*. Also applies in 2030.

TABLE 7: EXPANDED DER PROGRAM ASSUMPTIONS

Program	Segment	Program Impact	Participation [33]	
			2030	2050
LDV Managed Charging	Residential	90% of charging load [34]	12%	30% [35]
MHDV Managed Charging	C&I	75% of charging load [36]	5%	20% [37]
LDV V2G	Residential	Impact varies by hour [38]	N/A [39]	5% [40]
MHDV V2G	C&I	Impact varies by hour [41]	N/A	5% [42]
Water Heating	Residential	0.5 kW [43]	12%	25% [44]
Auto/manual DR	C&I	50% of load [45]	10%	15% [46]
Cooling DR	Residential	1 kW [47]	15%	45% [48]
Heating DR	Residential	0.7 kW [49]	10%	40% [50]

[33] National average. 2030 participation rates vary regionally to account for realistic ramp rates from today's levels. By 2050, we assume that unlocking DER barriers will enable the same participation rates across all regions of the US.

[34] Average hourly fleet charging load from NLR's EVI-Pro Lite tool. 10% opt-out based on observed impacts from PG&E, GMP, Eversource, and SEPA's *State of Managed Charging* report.

[35] SEPA, *The State of Managed Charging in 2024*, 2024.

[36] EIA, *AEO*, 2026. Average hourly fleet charging shape.

[37] Lower than LDV participation to account for lower willingness to participate for fleet types that are not compatible with managed charging. Also applies in 2030.

[38] Available fleet-wide capacity based on percent of vehicles parked at home by hour of day. Assumes 57.7 kWh battery (e.g., Tesla Model 3) and 30% backup requirement; 10% derate for opt-outs.

[39] V2G programs are modeled starting in 2035.

[40] Informed by primary market research and supported by UK pilot study. Participation ramp begins at 25% of full participation rate in 2035.

[41] Hourly load available to curtail assumes a 115 kWh/3-hour battery based on Blue Bird specs; available fleet-wide capacity based on percent of vehicles parked and plugged in (NLR 2025) and scaled down based on hourly SOC (NLR 2019). Minimum charge restricted based on hour and driving patterns (i.e., before school morning hours, battery can dispatch only down to 50% of charge versus 20% of charge overnight).

[42] Consistent with LDV V2G.

[43] Water heating hourly load available to curtail scaled to 8 kWh/day based on NLR, FL Solar Energy Center, and EIA RECS assumes 5% opt-out rate.

[44] Based on a review of water heating DR programs such as Great River Energy and ConEd.

[45] Based on a review of existing programs across CA utilities, Public Service Company of Oklahoma, and 2013 NYC-focused study. C&I demand varies based on coincident peak of customer segment.

[46] Informed by FERC reports, Voltus enrollment rates, and observations in WEPCO and ConEd.

[47] National average informed by Google and CenterPoint. Varies regionally.

Continued on next page

ii. Distributed PV

Addressing barriers in the distributed solar sector will primarily reduce costs to deploy distributed solar. Non-US jurisdictions (e.g., Australia) have much lower distributed solar deployment costs due to minimal permitting challenges. Residential solar costs in the Expanded DERs scenario decline to $1.5/W by 2035 to reflect the cost savings that can be achieved by reducing soft costs related to permitting, interconnection, marketing, and other administrative costs.[51] Soft costs, which represent 78% of rooftop solar costs today, are reduced from $2.9/W to $0.7/W (76% reduction) in 2035. The same soft costs reduction is applied to commercial solar over the 2026 to 2035 horizon, bringing total costs from $1.3/W in 2035 in the Status Quo scenario to $1.1/W in the Expanded DERs scenario.

When permitting and processes are streamlined, deployment costs will decrease and lead to some additional capacity deployment. The distributed PV forecast assumes that annual additions will increase by 10% relative to the Status Quo forecast to account for increased adoption when barriers are removed. However, as discussed in the Volume I report, this study assumes the primary benefit of the cost reductions is to enable more financially sustainable utility compensation for distributed solar, which reduces the cost to all existing ratepayers.

iii. Distributed Storage

The BTM storage forecast was developed using the same methodology as the Status Quo forecast, with stock attachment and participation rates, but increased to account for additional adoption when barriers are removed. We assumed a higher stock attachment rate of 35% for all residential, commercial, and community solar systems, informed by attachment rates observed in California.[52] We additionally accounted for customer battery adoption and participation that would be driven purely by the existence of a program and available performance payments.[53] Battery specifications vary by customer segment, all with dispatch capabilities up to four hours.

[48] Informed by observations in Xcel Energy, APS, PG&E, Duke, and Ontario utility programs.

[49] National average, informed by review of UK heat pump pilot and evaluation of PGE's winter smart thermostat program.

[50] Lower than Cooling DR to account for fewer available programs and winter load reduction needs.

[51] 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.

[52] LBNL, Tracking the Sun: 2025 Data Update, October 2025.

[53] As described in Brattle's assessment of Demand Side Grid Support (DSGS) program value, Tesla Energy conducted a regression analysis relating program compensation levels and uplifted adoption and found that 16% more customers would adopt distributed storage and enroll in demand response programs with the availability of DSGS-level compensation.

Additionally, we model FTM storage by assuming a portion of economically deployed utility-scale storage can be sited at customer locations. We assume 20% of economically deployed capacity could be sited FTM based on a review of emerging distributed projects and utility IRP announcements.[54] Customer-sited FTM storage is an emerging model that has gained traction in a high load growth and tight-supply environment.

d. Characterizing DER Operations

We account for DER-specific operational constraints that govern operational capabilities and the value these resources can provide to the system. Operational characteristics differ by DER type for each category described below.

- **Event frequency.** Unlike traditional generators, most DERs have limited dispatch frequency driven by customer behavior. For example, most smart thermostat programs can only be called ~10 times a season before customer discomfort reduces response. We capture event-limited resources by restricting DER events in the model.
- **Charging needs.** Certain DERs (e.g., distributed solar) provide generation while others (e.g., distributed storage) provide load reduction with charging requirements between events. We model DER-specific dispatch parameters that will drive value.
- **Hourly dispatch characteristics.** Each DER type has different hourly availability based on the underlying generation or load profile. For example, EV charging load that can be shifted is concentrated in evening hours, as opposed to the middle of the day when cars are on the road.

We modeled a deployment cost of $30/kW-yr to account for program administration.[55] Program incentives are derived from modeled net benefits that are shared across participants and non-participants.

6. Alternative Scenario 1: Overbuild Risk

The Overbuild Risk Scenario assesses the ability of DERs to mitigate risk in planning a system amid uncertain demand forecasts when load growth does not materialize at expected levels,

[54] For example, Xcel Energy Minnesota's Capacity*Connect program.

[55] Based on a review of various existing utility programs (such as residential battery, residential and C&I HVAC, EV managed charging, and auto C&I DR) and forecasted budget plans.

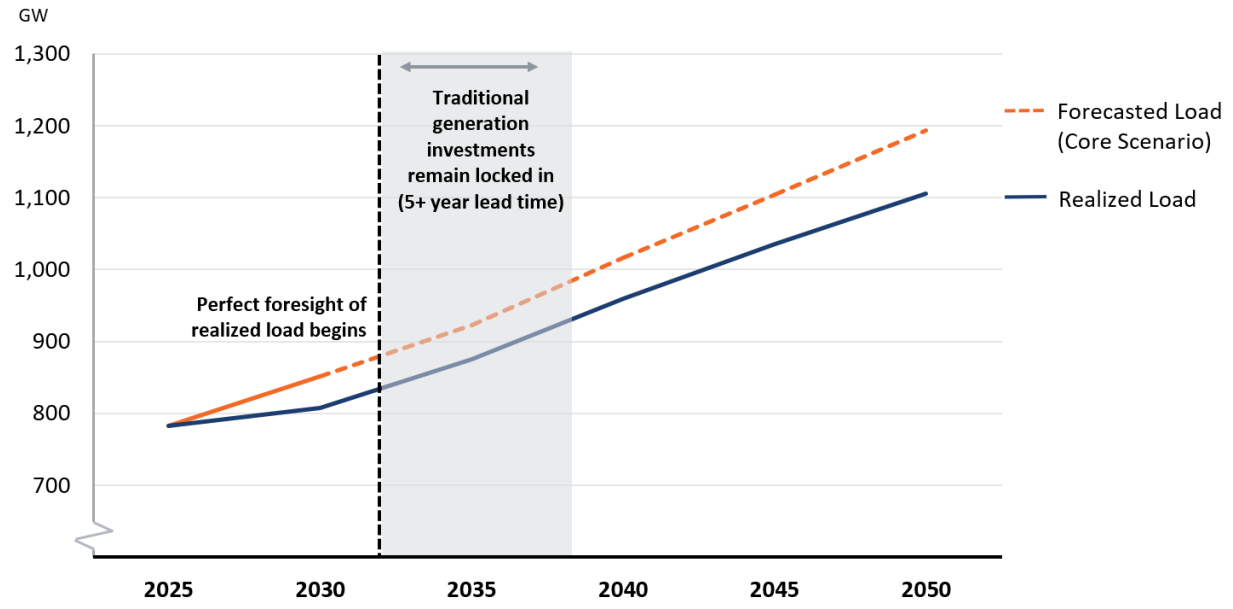
given their shorter deployment lead times, shorter asset lives, and modular nature. This scenario represents a system in which actual data center load growth falls short of planning forecasts. These findings apply to regions planning systems around additional demand uncertainty factors such as electrification.

This scenario anchors on two load forecasts: the Forecasted Load and the Realized Load that materializes. Forecasted data center load growth, consistent with the Core Scenario, is modeled based on EPRI's medium data center growth case. In the Realized Load case, data center growth materializes at lower levels based on the AEO 2026 forecast.[56]

Through 2030, system planners make investment decisions to reliably serve Forecasted Load. After 2030, planners adjust future investments to reflect the Realized Load, but conventional generation investments committed before 2030 remain fixed due to development lead times of five years or more. In contrast, DER deployment is committed two years in advance in this modeling, and can be scaled back beginning in 2032. The planning forecast and realized load forecasts are shown in Figure 9. By 2030, the overstated load forecast is 5% higher than the actual load in that year.

[56] EPRI, Powering Intelligence 2026, February 2026.

FIGURE 9: US LOAD FORECASTS FOR OVERBUILD RISK SCENARIO



For each of the two demand planning scenarios, we simulated both Status Quo and Expanded DERs forecasts, resulting in four total model runs to quantify the ability of DERs to mitigate overbuild risk, as shown in Figure 10.

FIGURE 10: OVERBUILD RISK SCENARIO APPROACH

		Foresight Case	
		Perfect Foresight (Realized Load) Investments reflect realized load growth throughout the planning horizon.	**Imperfect Foresight (Forecasted Load)** Investments through 2030 reflect higher forecasted load, with subsequent decisions adjusted to realized load.
DER Deployment Case	**Status Quo DERs**	Utility-scale generation investments are optimally deployed to match demand with **Status Quo** DER deployment consistent with the imperfect foresight case (scaled back starting in 2032).	Planning decisions made prior to 2030 to serve forecasted load persist, resulting in **overbuild** through the 2030s**. Status Quo** deployment of dispatchable DERs continues until 2032, then is scaled back to align with realized load.
	Expanded DERs	Utility-scale generation investments are optimally deployed to match demand with **Expanded** DER growth consistent with the imperfect foresight case (scaled back starting in 2032).	Planning decisions made prior to 2030 to serve forecasted load persist, resulting in **overbuild** through the 2030s. **Expanded** deployment of dispatchable DERs continues until 2032, then is scaled back to align with realized load.

Note: DER deployment is the same for the corresponding perfect foresight as the imperfect foresight case for modeling consistency.

In the imperfect foresight cases, conventional generation investments committed before 2030 remain fixed, resulting in excess capacity through the 2030s as load growth falls short of forecasts. For example, gas generation planned to serve 2035 demand may already be committed before the lower load trajectory becomes apparent. In contrast, DERs can be deployed incrementally with shorter lead times, allowing planners to defer or avoid conventional investments until load growth is more certain. DER deployment can also be adjusted through changes to program enrollment and incentives. We assume DER deployment decisions are committed two years in advance, allowing adjustments beginning in 2032.

Starting in 2032, for both the Status Quo and Expanded DER deployment cases, dispatchable demand response capacity is scaled back to existing levels and new distributed storage deployments are halted. These adjustments could be achieved through changes to program enrollment, marketing, and incentive levels. While there are behavioral considerations that would prevent dramatic year-to-year fluctuations in performance incentives, infrequent adjustments to the incentives are possible.

We estimated the value of DER flexibility under uncertain load growth as the reduction in overbuild costs achieved through Expanded DER deployment relative to Status Quo deployment. For each DER deployment case, overbuild costs are calculated as the incremental system costs under imperfect foresight relative to perfect foresight. Cumulative overbuild costs from 2030 to 2040 total $84 billion under Status Quo DER deployment, compared to $51 billion under Expanded DER deployment. Comparing the magnitude of this overbuild between the Status Quo and Expanded DER cases quantifies the avoided overbuild costs, the value of unlocking DERs in meeting load in an uncertain demand growth future.

These findings highlight the value of DERs as flexible, modular resources that can reduce the risk of overinvestment under uncertain load growth. While this scenario provides a simplified representation of investment timing and DER deployment flexibility, further research could assess how this value varies with load forecast uncertainty, conventional generation investment commitments, and the practical constraints on adjusting DER compensation.

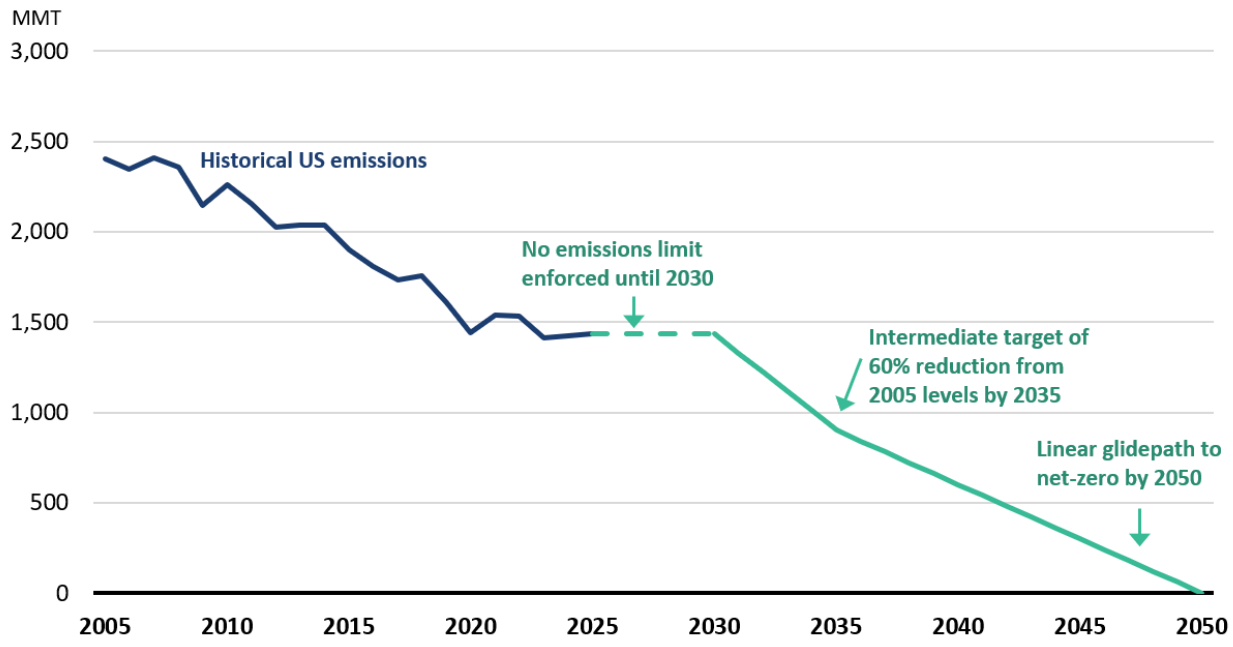
The allocation of overbuild costs among large-load customers, other ratepayers, and utility shareholders will depend on applicable tariffs, contracts, and regulatory treatment. For example, minimum-bill requirements for hyperscalers could mitigate cost exposure for other ratepayers. Because these arrangements remain highly uncertain, our analysis quantifies changes in total system costs rather than allocating cost recovery responsibility among individual customer groups.

7. Alternative Scenario 2: Full Decarbonization

The Full Decarbonization Scenario represents a transition toward a decarbonized power system (i.e., net zero power sector emissions by 2050) to quantify the affordability benefits that DERs enable as cost-effective, flexible resources. All modeling assumptions aside from the decarbonization requirement are the same as the Core Scenario.

We assumed a national net zero emissions requirement by 2050 that declines linearly from today's levels, with incremental target years consistent with the economy-wide emissions goal from the 2035 Nationally Determined Contribution Target (~60% reduction below 2005 levels) as shown in Figure 11 below.[57] Modeled clean technology options are consistent with the Core Scenario and include nuclear small modular reactors (SMRs), hydrogen turbines, and gas with CCS.

FIGURE 11: US ANNUAL POWER SECTOR CO2 EMISSIONS LIMIT FOR FULL DECARB SCENARIO



[57] Climate Action Tracker, 2035 NDC, November 2024.

8. Policy Scenarios

Addressing the current barriers that limit DER deployment will require action from all levels of the industry, from utilities and regulators to customers. The Expanded DER case assumes that all barriers to DER deployment are addressed. We quantify the impacts of three specific policy actions that contribute to removing these barriers, as described below, within the context of the Core Scenario.

a. Distribution Value

The Distribution Value Scenario assesses the impact of integrating DERs into distribution planning. DERs can provide meaningful value to the distribution by reducing load or dispatching in peaking hours that can defer an upgrade. However, most distribution plans do not comprehensively account for DER capabilities when determining investments. This policy scenario evaluates the additional system benefits of DER deployment when dispatchable DERs are integrated into distribution system planning and compensated for the distribution value they provide. Across all cases, including Status Quo, we assume distributed solar indirectly provides distribution value since utility load forecasts commonly reflect distributed solar generation in existing distribution planning practices, unlike dispatchable DERs. Details on the value calculation approach are included in our Volume I report and above in Section 4.

b. Interconnection Reform

The Interconnection Reform Scenario assesses the impact that improved interconnection has on facilitating DER integration. Interconnection reform can create additional headroom that facilitates faster interconnection for exporting DERs, increasing total potential and improving program economics. To model this policy, we adjusted the exporting DER programs (BTM distributed storage and LDV/MHDV V2G) as follows:

i. Distributed Storage

With current interconnection standards, only a limited subset of distributed storage can export to the grid – the rest is restricted to self-consumption or other limited dispatch modes. Based on a review of existing storage VPP programs, we estimated that approximately 25% of customers currently have access to a BTM storage VPP program. We estimated this number by mapping existing storage VPP programs to utilities and comparing the number of residential

customers served by these utilities to the total number of residential customers in the US.[58] We use an existing storage VPP program as a proxy for the share of customers that are compensated for full storage dispatch.

Without interconnection reform, we forecast that VPP program availability does not expand. Therefore, the 75% of customers whose utility does not currently offer a battery storage program would remain unable to receive export compensation through 2050 in the absence of policy reform.

To represent the impact of expanding export capability, we assume that policy reform enables 75% of new BTM storage additions to export to the grid. These systems can therefore dispatch beyond the customer's load, allowing the battery to both reduce hourly demand and provide net exports to the grid.[59]

ii. EV V2G

For LDV V2G resources, we assume that interconnection reform enables vehicles to export electricity in excess of the customer's load. This expands V2G capability beyond vehicle-to-home applications, allowing participating LDV EVs to both reduce customer load and provide additional energy to the grid.[60]

For MHDV resources, we assume that interconnection reform is required for MHDV V2G capability. All MHDV V2G participants are assumed to be school buses, which typically charge at centralized depots rather than at locations with customer load that can be offset.[61] With interconnection reform, these resources can export directly to the grid and provide both load reduction and capacity value.

c. Permitting Reform

The Permitting Reform Scenario assesses the impact of more streamlined permitting processes on lowering distributed solar costs. According to Permit Power, permitting costs are around

---

[58] Battery VPP programs based on CESA program database; program utility mapping and customer counts based on data from 2025 Form EIA-861.

[59] We assume an average residential customer load of 2 kW.

[60] We assume an average residential customer load of 2 kW.

[61] School Bus Fleet, "The State of Electric School Buses: Where We Are and Where We're Going," September 2025.

14% of total residential rooftop solar costs today (around $0.50/Watt). [62] Through more streamlined permitting protocols, such as enabling instant online permitting, remote inspections, and shortening timelines, permitting costs can be reduced by more than 90%, to around $0.05/Watt. To isolate the impact of permitting reform, we reduce residential distributed solar costs from the Expanded DER scenario levels by $0.45/W (from $1.95/W to $1.5/W). The same relative decrease in soft costs is applied to commercial distributed solar.

[62] 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.