Faster and Cheaper

Demand-Side Solutions for Rapid Load Growth

Mike Specian and Alex Aquino

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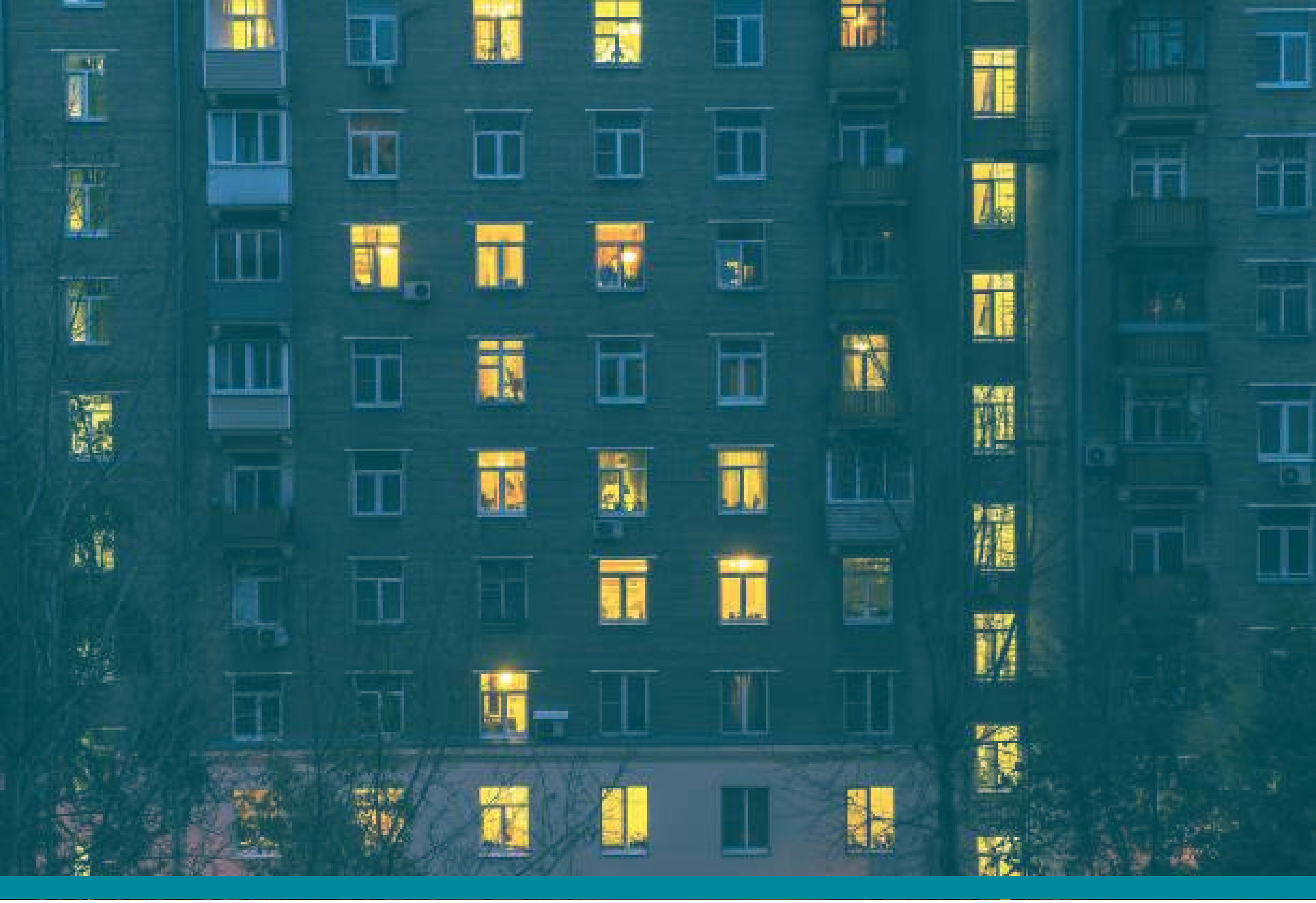
Research Report

ACEEE



About ACEEE

The **American Council for an Energy-Efficient Economy** (ACEEE), a nonprofit research organization, develops policies to reduce energy waste and combat climate change. Its independent analysis advances investments, programs, and behaviors that use energy more effectively and help build an equitable clean energy future.

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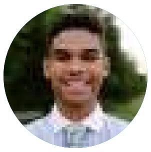

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Data and licensing information

Contents

Executive summary

Key findings

- Energy efficiency and load flexibility have enough untapped potential nationally to significantly offset the unprecedented forecasted load growth (i.e., electricity consumption and peak demand) driven by data centers, industry, and the electrification of transportation and buildings.
- Our analysis of the nation's largest utility programs shows that energy efficiency (~$21/MWh) and load flexibility (<$40/kW-year) are currently the lowest-cost resources for reducing electricity consumption and peak demand. Yet, despite an energy affordability crisis, many jurisdictions are responding to load growth by approving additional gas generation.
- Demand-side measures are quicker to implement and provide a cleaner alternative to building new generation. They offer a "no-regrets" approach to managing load growth uncertainty and protecting ratepayers from adverse impacts.
- Business-as-usual approaches are not delivering efficiency and load flexibility at the scale required to meet projected load growth. Legislators, utilities, utility regulators, and large load customers (e.g., data centers) must act now to accelerate demand-side solutions while accounting for the large regional variations shaping where and how load growth occurs.

New drivers of electricity demand are emerging, fueling a surge without recent precedent. This explosive load growth is being driven by the rapid expansion of data centers (including those supporting artificial intelligence), new and expanded factories, and the comparatively more gradual adoption of electrified space heating, water heating, transportation, and industry. Forecasts suggest that over the next 10 years the need for electricity will increase 20–50%, while peak demand will increase 19–35% in both summer and winter.

States and utilities nationwide are grappling with how to meet this challenge, with new gas generation being the most common response to maintain energy supply. Utilities have historically overestimated future demand, and uncertainty about when new loads—especially data centers—will emerge risks creating stranded generation, transmission, and distribution assets, saddling ratepayers with unnecessary additional expenses.

The evidence presented in this report supports the conclusion that demand-side management (DSM)—energy efficiency (EE) and load flexibility—should be the first-line option for addressing load growth.

Massive potential

Energy efficiency and load flexibility remain untapped resources in the United States. By 2040, energy efficiency aggregated nationally realistically has the potential to reduce electricity consumption by about 8% and demand by about 70 GW. In addition, most experts agree the United States has about 60–200 GW of load flexibility potential available within the next decade, which by itself is roughly 1–2 times larger than the most aggressive projections of total U.S. data center capacity in 2030. Utility demand-side management programs will be essential in helping to realize this potential.

Less expensive

Rapidly rising electricity bills have created an affordability crisis in the United States, particularly for low-income households. There is a pressing need to drive down electricity costs, and demand-side measures offer an ideal solution. Our analysis of the nation’s largest utility programs reveals that the median cost of energy savings achieved through utility EE programs is $20.70/MWh, a value significantly below the cost of all other supply-side resources. Moreover, the cost comparison illustrated in figure ES-1 does not even account for EE’s ability to reduce distribution system costs (e.g., substations, transformers, power lines), which are projected to be among the largest costs created by load growth in the absence of DSM.

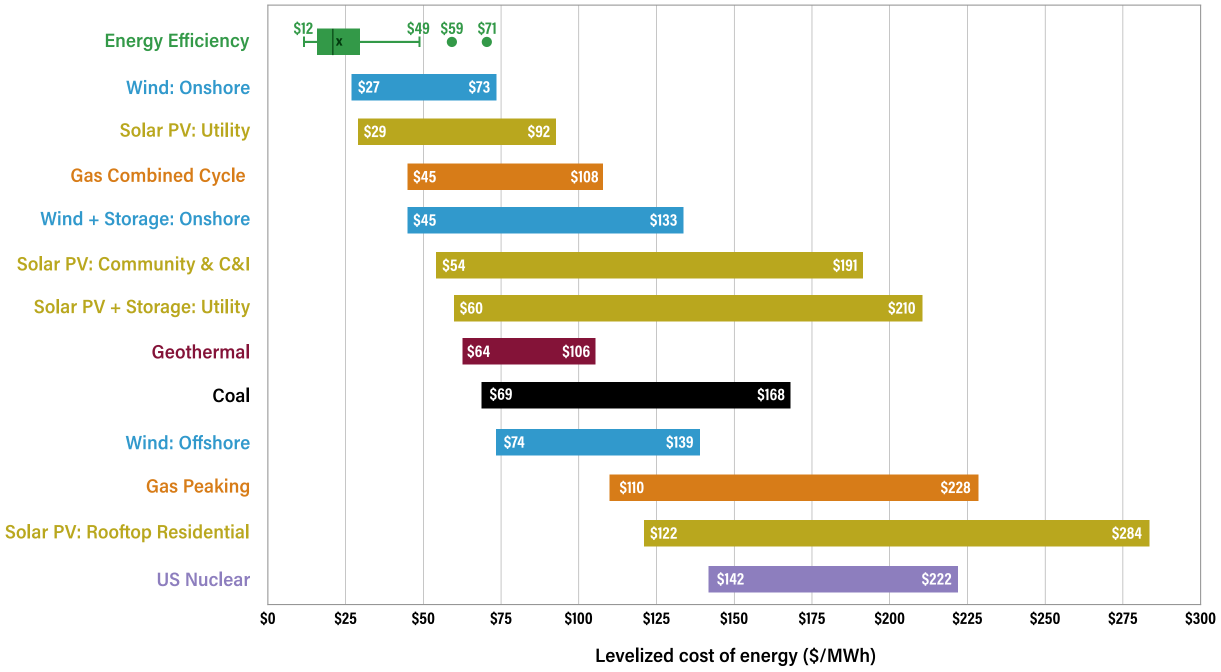

Figure ES-1. A comparison of the levelized cost of energy efficiency and supply-side resources. Vertical line and "X" represent the median and mean costs of energy efficiency, respectively. Cost data for supply-side resources calculated by Lazard (2024).

Utility load flexibility programs also achieve peak load reduction at lower cost than supply-side resources. The lowest-cost supply-side resource prices in at $51.72 per kilowatt per year. Utility load flexibility programs can deliver peak demand reduction at a fraction of that cost (see table 4).

Faster

Demand-side resources are ideal for avoiding the cost, siting, environmental compliance, emissions, and delay issues associated with new generation, distribution, and transmission. Utilities have been running DSM programs for decades and are experienced in delivering these benefits to customers and the grid. They can also be ramped up relatively quickly. Since 2015, the fastest-growing utility EE programs had an average annual growth rate in lifetime energy savings of about 43% over a triennium. Virtual power plants can be operationalized in less than six months. Only 6.0% of U.S. energy consumers participated in a retail demand response (DR) program in 2024, demonstrating the massive opportunity to expand the resource.

In comparison, procuring and deploying supply-side resources are considerably slower. Large gas turbines are likely to take 5–7 years to be delivered. Long interconnection queues force solar and wind projects to wait five years on average to connect to the grid. Upgrading and expanding the distribution system can require a similar amount of time or longer to procure equipment and work out land use and permitting issues. The wait for transmission lines often takes a decade or more.

An additional advantage of demand-side measures is that they can be targeted to the regions where load growth relief is needed most without the need to enter lengthy interconnection queues. By reducing load, DSM provides more headroom by freeing up capacity on existing utility infrastructure, thereby enabling a faster accommodation of technologies like electric vehicles and heat pumps without creating distribution bottlenecks.

Better

DSM offers numerous advantages over supply-side solutions while serving as a complementary component to them. It provides a hedge against load and price uncertainty. Ratepayers in vertically integrated markets are often on the hook for new supply-side expenses, whether new load materializes or not. Should load emerge, DSM lightens the load that must be met with generation resources at lower cost than new supply-side investments. Should load not emerge, the utility will have procured a least-cost energy resource that benefits both participating customers and other ratepayers by reducing energy and capacity costs. Demand-side measures also buy utilities time to meet near-term energy needs while waiting to see which loads will actually materialize.

The alternative to maximizing demand-side resources is likely to be massive expenditures for new gas plants and delayed retirements of existing fossil plants. Meeting data center load with fossil resources through 2035 is projected to increase cumulative carbon emissions significantly—by an amount equal to about 10% of 2025's total global emissions—with the United States and China being the largest contributors by far. This would make it considerably harder to reach decarbonization goals and consign the planet to the avoidable negative outcomes of climate change. A focus on DSM also supports domestic manufacturing and our workforce while avoiding global bottlenecks on supply-side equipment.

Recommendations

Load growth will vary regionally and with time. While specific solutions will need to be tailored to each state's unique circumstances, there are multiple options that all states and utilities should consider. These include the load flexibility strategies presented in table ES-1 and the lengthy list of EE measures provided in Appendix C: Cost of energy efficiency and load flexibility.

Table ES-1. End uses, technologies, and program types that can support load flexibility

Category	Technology examples	Program types	Application
HVAC	Smart thermostats, advanced HVAC controls	Smart thermostat rebates, direct load control, time-of-use rates	Residential, commercial
Water heating	Connected/smart water heaters, load-shifting controls	Direct load control, dynamic pricing, bring your own device (BYOD), smart water heater incentives	Residential, commercial
Batteries	Distributed battery storage, commercial-scale storage	Installation incentives, virtual power plant (VPP) and battery aggregation programs	Residential, commercial
Electric vehicles	Grid-interactive charging (smart charging, V2G/V2B, networked charging stations, etc.)	Off-peak charging incentives, managed charging, and smart charging equipment incentives that support grid-responsive EV charging.	Residential, commercial
Large commercial and industrial demand response	Building management systems, automated DR platforms, onsite renewable generation/storage	Pay-for-performance, interruptibility agreements, time-varying rates, technology incentives	Commercial, industrial
Whole-building	Any behind-the-meter load	Voluntary behavioral demand response; customers encouraged to reduce load using whatever method they choose	Residential, commercial, industrial

There are roles for legislators, utilities, regulators, and large load customers in enabling EE and load flexibility to deliver their full potential. Many of these recommendations are well-established actions that have become increasingly valuable, but we also present new approaches specifically designed to meet the current moment. A list of approaches organized by the actors most responsible for their implementation is provided in table ES-2.

Table ES-2. Summary of demand-side actions decision makers can take to address load growth

Decision maker	Recommended actions
Legislators	• Introduce or strengthen energy efficiency resource standards (EERS) • Set or empower regulators to set and enforce specific utility load flexibility goals • Enable revenue decoupling to eliminate the incentive for utilities to maximize electricity sales • Enable or mandate performance incentive mechanisms (PIMs) that reward utilities for addressing load growth through DSM • Require updated market potential studies (MPS) that evaluate granular time- and location-based DSM opportunities • Eliminate opt-out provisions or require new large load customers to support DSM that benefits their local grid as a condition of their interconnection • Require large load customers to share pertinent energy-related data needed to assess DSM opportunities • Require regulators and utilities to establish virtual power plants (VPPs) and authorize third-party demand response aggregation
Utility regulators	• Set and enforce utility load flexibility goals • Approve and oversee demand-side PIMs • Require utilities to evaluate and communicate load flexibility options for and to large load customers • Require that updated market potential studies include granular assessments (e.g., feeder level) and consider novel DSM opportunities • Require utilities to adhere to best practices during large load tariff and related proceedings, including a requirement that large load customers engage in an integrated resource plan (IRP)-like process to determine the optimal set of demand- and supply-side resources to meet grid needs (a la all-source procurement) • Require utilities to evaluate VPPs as part of their resource planning processes • Require utilities to share data necessary for third-party aggregators to propose optimized DSM solutions • Analyze and support the potential of thermal energy networks through regulatory proceedings

Decision maker	Recommended actions
Utilities	• Provide large load customers with benefits—such as guaranteed access to firm capacity—in return for their commitment to deliver or financially support additional demand-side management resources on the system • Prioritize energy efficiency measures that will reduce peak load in the building sector (e.g., higher-efficiency heat pumps, weatherization) • Launch or expand managed charging and vehicle-to-grid programs to reduce peak load and improve system resilience • Provide technical assistance to data centers prior to interconnection on how to reduce energy consumption and peak demand • Introduce or expand demand flexibility programs, including virtual power plants
Large load customers	• Maximize efficiency and load flexibility capabilities of your facilities prior to interconnection and, if possible, construct thermal energy networks to repurpose waste heat • Actively engage with utilities and other subject matter experts prior to interconnection to determine how to maximize facility's DSM potential • Advocate for capacity accreditation for load reductions achieved as a result of new DSM investments, including those realized through additional financial support of utility programs • Utilize energy attribute certificates (EACs) (i.e., demand-side renewable energy credits) to procure demand-side resources on the private market

Introduction

The U.S. electric system is entering a period of unprecedented electricity demand growth. After nearly two decades of relatively flat consumption, in large part due to steady improvements in energy efficiency, the landscape is shifting dramatically. New drivers of electricity demand have emerged, fueling a surge without recent parallel in scale or pace. While forecasts continue to evolve and vary across regions and studies, the growth trend is clear. One representative study shows electricity consumption growing 25% by 2030 and 78% by 2050, and peak demand growing from 14% in 2030 to 54% by 2050 (Batra et al. 2025).

Large loads refer to very high electricity demand customers, facilities that consume power at a scale far beyond typical commercial or residential users, and the aggregated impact of new electrified end uses. This surge in the near term is driven largely by the rapid expansion of data centers supporting advanced technologies such as artificial intelligence (AI). The early 2020s marked the rise of large language models and other AI innovations, which have rapidly increased the power needs of data centers designed to support these computationally intensive tasks. Data center power demand alone is expected to double to roughly 35 gigawatts (GW) by 2030, creating unprecedented new demand across many parts of the country (FERC 2024b). New manufacturing capacity, driven in substantial part by government investment in strengthening domestic supply chains, will contribute significantly to load growth as well. Semiconductor, battery, and other clean technology production could add 1.5–3 GW of new load per year through 2030 (Citi Group 2025).

Other load growth drivers are emerging more gradually. Electrification of space and water heating have begun to shift load from the gas system and delivered fuels (e.g., propane) onto the electric grid, particularly during cold weather. This seasonal load will transition multiple regions of the country from experiencing peak demand in summer to winter. Electrification of transportation (e.g., electric vehicles (EVs)) will also add significant load to the grid, though the timing of these loads will depend on charging strategy.

Utilities, regulators, and independent system operators (ISOs) and regional transmission organizations (RTOs)[1] nationwide are actively grappling with how to meet this challenge. In some cases, default responses involve building new gas-fired generation or delaying fossil plant retirements, which risk high costs, increased emissions, and infrastructure bottlenecks (Malik and Saul 2025). Adding more supply-side resources could exacerbate challenges already facing America's grid infrastructure. Large portions of transmission and distribution systems are aging, and transmission line buildout has slowed due to siting and permitting barriers.

The central finding of this report is that demand-side management (DSM)—energy efficiency (EE) and load flexibility—offers a faster, cheaper, more flexible, and lower-risk path than supply-side-only expansion. Demand-side measures can quickly be deployed at scale and provide critical comparative advantages: They reduce costs for utilities and customers, can be implemented sooner than new generation, and complement renewable resources to enhance grid flexibility and reliability.

To maximize impact, these strategies should be tailored to the specific drivers of load growth and system conditions within each state or utility service area. Achieving this potential, however, will require utility planning and regulatory decision-making processes to evolve rapidly; without such shifts, business-as-usual approaches risk underinvesting in DSM and falling short of the benefits these strategies can deliver.

Report structure

This report is written for four primary audiences:[2]

- Legislators seeking solutions to address load growth quickly, reliably, and at low cost
- Regulators charged with balancing affordability, reliability, and sustainability who need a framework to evaluate and promote DSM as a cornerstone of least-cost resource portfolios
- Utilities facing the challenge of resource planning amid rapid load growth in need of strategies and data to guide integrated DSM adoption
- Large load customers who seek to utilize DSM to help meet their electricity resource needs

This report builds on and complements recent analyses by others focused on the implications of electric load growth on rate design, renewable integration, and siting of generation and transmission. By quantifying the savings potential and cost effectiveness of demand-side resources relative to supply-side alternatives, we seek to build the confidence utilities, regulators, and advocates need to elevate these measures as robust first-line strategies.

The report begins with a chapter on The load growth challenge. It details the scale of load growth across the United States, the impact of specific load growth drivers, and a breakdown of how much each driver is expected to affect each region of the country. This chapter will be useful for those seeking to understand which load growth drivers are projected to have the greatest impact on their local electricity systems.

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[1] ISOs and RTOs manage the electric grid and wholesale power markets to ensure reliable electricity delivery and efficient competition across large regions.

[2] This report does not focus on the specific roles of ISO/RTOs in wholesale markets, though many of the recommendations herein (e.g., procuring more demand flexibility) are applicable to these entities.

The second chapter, DSM as a solution, quantifies how much EE and DR potential exists in the United States, showing that DSM is more than capable of addressing the load growth challenge. The section Advantages of demand-side measures demonstrates that EE and demand response (DR) are the least-cost resource solutions to mitigating new energy consumption and peak demand growth. This section also explains how DSM is a “no-regrets” strategy that protects ratepayers and keeps electric rates affordable, is faster to deploy than supply-side resources, and more effectively mitigates the harmful effects of climate change. The contents of this chapter will be of interest to those seeking data and insights to support the relative merits of DSM over supply-side alternatives.

The third chapter, Policy and program approaches, describes what is currently being done on both the supply and demand sides to respond to load growth. The section Current policy responses underutilize EE and DR summarizes the features of emerging legislative solutions that would strengthen the role of DSM, particularly in response to data centers. The chapter concludes with the section Technology priorities and program models, which identifies the key DSM program categories for mitigating load growth, as well as the most important features for those programs. This chapter will be most useful for policymakers and program designers who want a playbook of options for responding to load growth.

The main body of the report concludes with Recommendations for legislators, regulators, utilities, and large load customers. It details the actions each decision maker can take to ensure DSM is best utilized.

This report also contains four useful appendices. Appendix A: Load growth forecasts provides supplemental details on regional and driver-specific load growth forecasts. Appendix B: Select state load flexibility potentials offers select examples of regional DR potentials in Indiana, Massachusetts, New York, California, and Texas. Appendix C: Cost of energy efficiency and load flexibility provides data and derivations to support this report’s cost of EE and DR conclusions. It also contains a comprehensive list of energy efficiency and load flexibility measures that program designers and other decision makers should reference to ensure they are getting the most out of DSM. Appendix D: Additional policy approaches and program examples dives into detail on specific policies and programs that can serve as models for those seeking to implement DSM solutions for themselves.

The load growth challenge

The addition of electric end uses (i.e., loads) to the grid is causing the phenomenon we refer to as "load growth." Load growth affects the electricity system in two key ways. First, it increases the amount of electricity that needs to be generated to serve those new loads. This impact is quantified in units of energy—typically megawatt-hours (MWh) or terawatt-hours (TWh).[3] The electric grid satisfies this additional need by running more dispatchable generators, including those that otherwise would have been idle. This outcome often increases the wholesale cost of electricity and can lead to a greater amount of harmful emissions.

Second, load growth increases the electric grid's peak demand, or the largest amount of energy that needs to be served over a period of time. Electric demand is quantified in units of power, usually in megawatts (MW).[4] Electric utilities have an "obligation to serve," meaning they must provide enough grid capacity (also measured in MW) to ensure all loads can be served when the collective need for electricity is at its highest. Grid capacity can be increased by actions like constructing and interconnecting new power plants and removing power delivery constraints by adding new transmission lines or repowering and upgrading existing lines, expanding the distribution system, and building new substations. These additional costs can be significant and are ultimately passed on to ratepayers—whether that infrastructure ends up being utilized or not.

Within this report, we address the impacts of load growth on both energy usage (in MWh) and peak demand (MW). Terminology can become a point of confusion, as the word "demand" has two different meanings in the context of load growth. When we refer to "demand" in this report, unless otherwise specified we are referring to the additional capacity (i.e., power) that would need to be installed and come online in order to serve those new loads. When the word shares the same meaning as in "supply and demand," we will use the word "need" instead of "demand."

Programs that shift or reduce loads in specific hours in response to grid signals are known as "load flexibility" or DR programs. This report draws no distinction between the two and uses the terms interchangeably.

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[3] One terawatt-hour equals 1,000 gigawatt-hours (GWh) equals one million megawatt-hours equals one trillion kilowatt-hours (kWh).

[4] Power is equal to energy divided by time. One megawatt of demand is equivalent to one megawatt-hour of energy generated over one hour.

This chapter provides insight into the four main drivers of explosive load growth: data centers, new industrial loads, transportation electrification, and building electrification. The section The scale of load growth briefly summarizes the size of the overall load growth challenge that must be addressed. In the section Load growth drivers we provide additional details on how data centers, industry, transportation, and buildings will each contribute to the load growth challenge. This chapter concludes with the section Load growth by region in which we identify which load growth drivers are poised to grow the largest in which regions. Resource planners can use this information to identify the specific needs of their regions.

Supporting details for this chapter are provided in Appendix A: Load growth forecasts. Examples of demand-side solutions to address these needs are provided in a later chapter, Policy and program approaches.

The scale of load growth

Almost all experts agree that explosive load growth is coming, though individual forecasts of the magnitude of load growth differ. This uncertainty is a major challenge for grid planners, who are responsible for ensuring that enough energy resources (supply side or demand side) are available to meet customer needs. Procuring too many supply-side resources will saddle electric ratepayers with increased costs, exacerbating problems with affordability. Procuring too few resources can lead to power outages.[5]

After two decades of relatively flat electricity consumption, the need for electricity and demand capacity is projected to increase significantly. Utilities project peak demand will increase 166 GW in the next five years, with data centers responsible for about 55% of that (see figure 1) (Wilson et al. 2025). Other forecasts suggest that over the next 10 years the need for electricity will increase 20–50%, while peak demand will increase 19–35%. Similar peak demand increases are projected for both summer and winter, necessitating bespoke solutions for each (Chandramowli et al. 2024; NERC 2024; Newell et al. 2025).

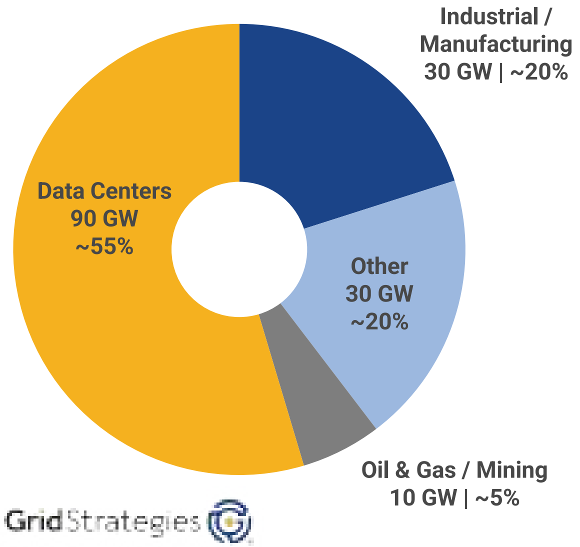

Figure 1. Drivers of load growth from 2025–2030. Estimates are based on utility forecasts submitted to FERC. Data compiled and figure created by Wilson et al. (2025).

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[5] Refer to the sections **Protecting retail customers** and **No-regrets option** to understand how demand-side resources are the ideal first-line option for handling load growth uncertainty.

Load growth drivers

Key contributors to explosive growth include the proliferation of large data centers, new industrial loads (e.g., battery and hydrogen production), transportation electrification (e.g., electric vehicles), and electrification of space and water heating in buildings. While experts may disagree on the relative contribution of each driver, there is consensus that load growth in each of these four sectors will be significant. As shown in figure 2, the Electric Power Research Institute (EPRI) projects that by 2030 data centers will be responsible for 25% of increased electricity usage, with the remainder split among industry (28%), buildings (26%), and transportation (21%) (Koomey et al. 2025).

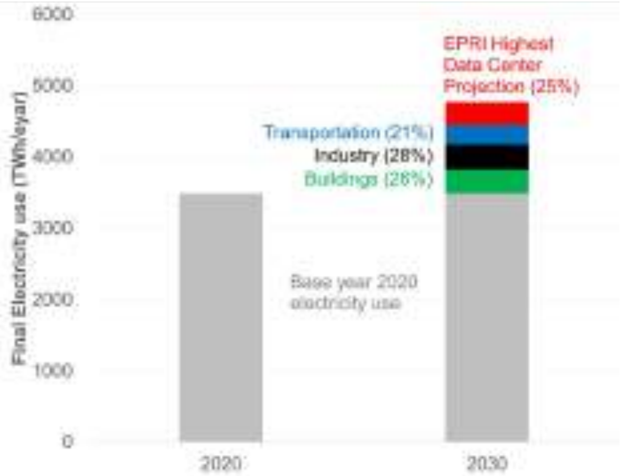

Figure 2. Projected electricity use in 2030 by sector relative to 2020 usage according to EPRI. Energy use in 2030 assumes a high electrification scenario. Figure sourced from Koomey et al. (2025).

An independent projection from the National Electric Manufacturers Association (NEMA) (see figure 3) finds that data centers are likely to be the leading cause of electricity consumption in the near term, with transportation electrification next in line. In the long term, EVs become the primary driver of new electricity consumption with new industrial electric loads also playing a substantial role.

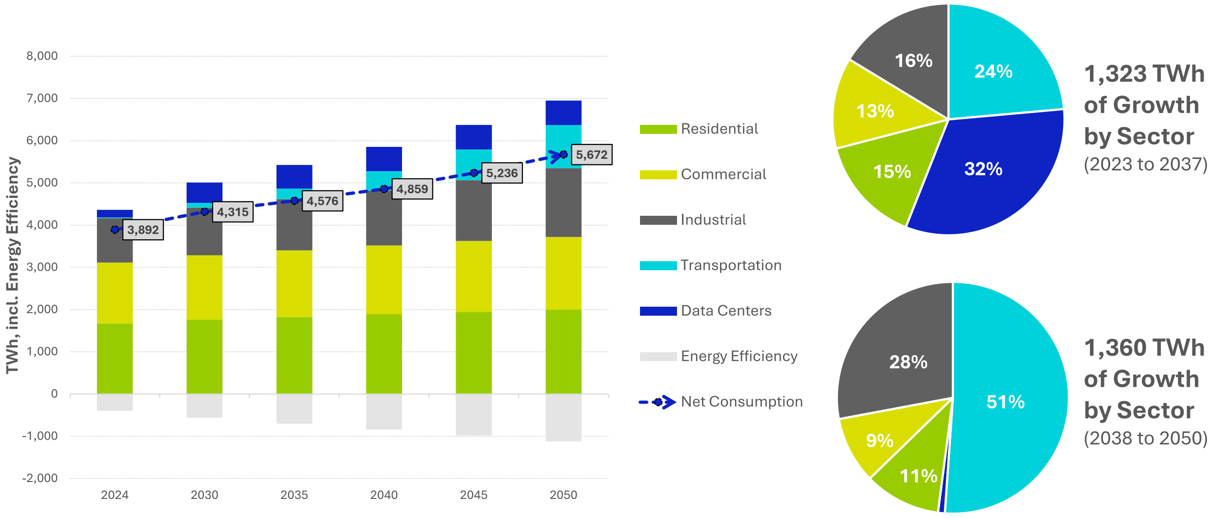

Figure 3. Projected U.S. net electricity consumption by sector. Data and figure sourced from NEMA (2025).

However, it is important to note that the **passage of the One Big Beautiful Bill (OBBB) Act** in July 2025 eliminated tax credits that supported many of these industries—such as hydrogen production, transportation electrification, and heat pump deployment—at least temporarily. The impacts of this sudden and massive policy shift are not yet fully understood, but **will add significant uncertainty into load growth projections.**[6] Utilities that base their load forecasts on end uses that may not materialize (or that may not materialize in their service territory) are more likely to waste financial resources paying for unneeded capacity. Those added capacity costs will be passed onto ratepayers, increasing their utility bills at a time when energy affordability is of major concern.

Data centers

Data centers accounted for about 4% (176,000 GWh/year) of U.S. electricity usage in 2023. In that year, fifteen states accounted for about 80% of data center load. From highest load to lowest those 15 states are Virginia, Texas, California, Illinois, Oregon, Arizona, Iowa, Georgia, Washington, Pennsylvania, New York, New Jersey, Nebraska, North Dakota, and Nevada (Aljbour and Wilson 2024).

This load is set to surge both nationally and globally through 2030, with growth driven primarily by hyperscale cloud and AI-ready facilities (Shehabi et al. 2024).[7] However, projections for U.S. data center load in 2030 vary widely. At the low end, scenarios foresee demand in the 16–24 GW range, assuming aggressive efficiency improvements and minimal AI expansion. More moderate scenarios cluster around 33–46 GW, reflecting significant but managed AI and cloud expansion. Aggressive outlooks project that U.S. data center demand could soar to 65–132 GW, driven by rapid, unconstrained AI adoption and technological breakthroughs. A summary of these projections is provided in table 1.

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[6] For more up-to-date details on how investments are affected by the OBBB Act, we recommend the Big Green Machine, a project run out of Wellesley College that tracks investments in clean energy supply chains in North America, including the wind, solar, battery, and electric vehicle industries (Turner 2025).

[7] Hyperscale data centers are large-scale facilities, typically 10,000 square feet or more (though usually much larger in practice). They deliver high capacity, wholesale services for major cloud and tech companies like Amazon and Google, supporting massive, dedicated deployments of thousands of servers to meet their intensive computing, storage, and analytics needs (Equinix 2020).

Table 1. Data center load growth projections, 2023–2030

Source/Scenario	2030 Projections (GW)	Assumptions/Notes
Schneider Electric – Limits to growth scenario (Paccou and Wijnhoven 2025)	16.4	AI development is intentionally restricted by policy or regulation, keeping energy demands and growth in check
EPRI – Low growth scenario (Aljbour and Wilson 2024)	22.4	3.7% CAGR,[8] 196 TWh/year
EPRI – Moderate growth scenario	24.4	5% CAGR, 214 TWh/year
Schneider Electric – Energy crisis scenario	Peaks at 32.3, drops to 24.1	Uncontrolled AI expansion overwhelms power systems, leading to instability and systemic failures
EPRI – High growth scenario	33.8	10% CAGR, 296 TWh/year
Schneider Electric – Sustainable AI scenario	33.8	AI growth is guided by energy efficiency and sustainability goals, enabling innovation without exceeding environmental or grid limits
FERC (2024b)	35	U.S. data center demand doubles from 17 GW (2022) to 35 GW (2030)
EPRI – Higher growth scenario	46.1	15% CAGR, 404 TWh/year
Schneider Electric – Abundance without boundaries scenario	65.3	AI efficiency leads to runaway development and surging energy use, driven by Jevons paradox and heavy reliance on fossil fuels
Grid Strategies (range) (Wilson et al. 2025)	10–65	High end and low end of leading industry estimates
McKinsey & Company (Green et al. 2024)	>80	U.S. demand grows from 25 GW (2024) to over 80 GW (2030) at a CAGR of ~23%
Boston Consulting Group (Berns et al. n.d.)	100–130	15-20% annual growth
LBNL (Shehabi et al. 2024)	74–132	Projected annual growth between 13% and 27% from 2023 through 2028

Each of these projections is shaped by distinct underlying assumptions, including anticipated improvements in AI's energy efficiency (electricity consumed per computation) and computational efficiency (amount of computation performed per unit of hardware), upgrades to the electric grid, varying rates of AI adoption, and a range of external influences such as regulatory and policy developments. These factors collectively drive differences in projected growth rates and highlight the complexity and uncertainty inherent to forecasting AI's future energy impact.

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[8] Compound annual growth rate, or the average annual growth rate of an investment over a specified period (assuming profits are reinvested).

This uncertainty has already found its way into utility load growth forecasts. According to data submitted via FERC Form 714, utilities expect roughly 90 GW of new data center load to materialize by 2030 (Wilson et al. 2025). By 2030, data centers' share of national electricity usage is projected to rise to between 9% (Denman et al. 2025) and 12%, reaching as much as 580 TWh (Shehabi et al. 2024). Utility forecasts project a 32% increase (Wilson et al. 2025).

However, caution is warranted when considering the upper range of these projections for several reasons. First, data center load forecasts are particularly prone to inflation because of the way data center developers interact with utilities during site selection and project planning. **Utilities often receive multiple interconnection requests for the same project** (i.e., from project owners and developers), **and the same project may appear in multiple utilities' forecasts. Just because a data center appears in a utility forecast does not guarantee it will actually be developed.** Moreover, data centers are often developed under nondisclosure agreements, so neither the utilities nor the ISO/RTOs generally have visibility into other utilities the data center companies are communicating with.

For example, Dominion Energy's Q4 2024 earnings call revealed that out of 40.2 GW of contracted data center capacity, only 8.8 GW had firm electric service agreements, while the majority—26.2 GW—were engineering authorizations without any commitment to build (see figure 4) (Dominion Energy Q4 2024 earnings call 2025).[9] This means that much of the projected demand is based on speculative projects, contributing significantly to the large and variable forecasts currently seen.

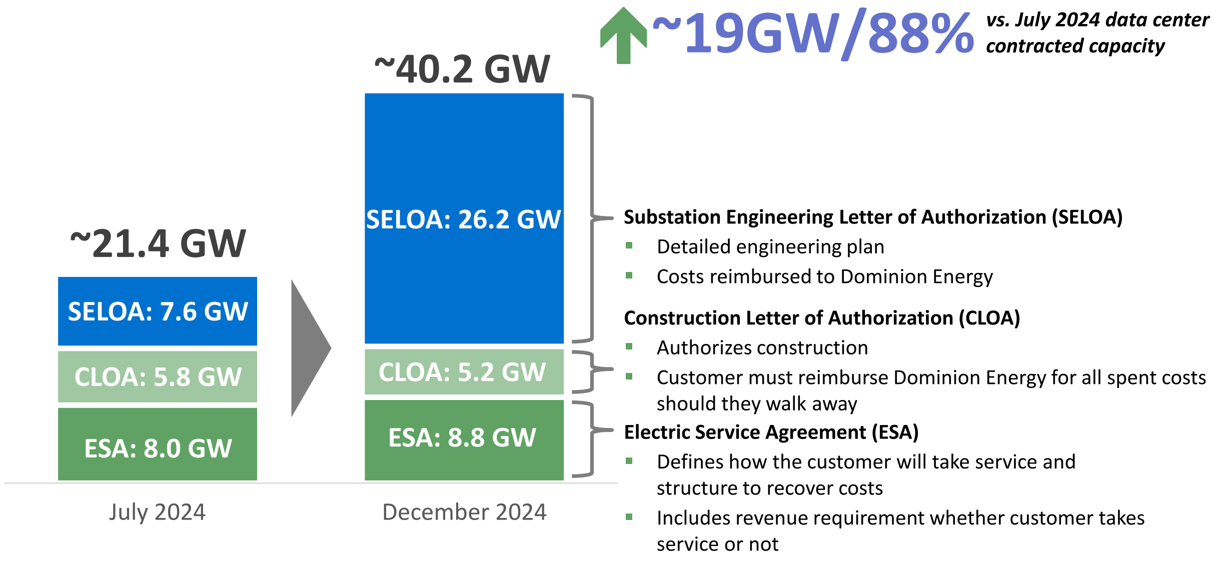

Figure 4. Dominion Energy Virginia data center contracted capacity. Figure from Q4 2024 earnings call.

Second, data center load varies significantly by purpose (e.g., cloud services, AI training, AI inference), and data center developers are reluctant to share even the nameplate capacity of their facilities (DOE 2024; St. John 2025b). **These factors make it difficult for utilities to accurately forecast both the timing and scale of future power demand from new data**

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[9] A Substation Engineering Letter of Authorization (SELOA) is a contract that authorizes a utility to perform detailed engineering work for a potential customer project but does not represent a commitment to build the project. Utilities include SELOA capacity in their load growth forecasts because these agreements indicate customer interest and require the utility to begin planning. However, since many projects at the SELOA stage never progress to construction or operation, including them can inflate projections and overstate likely future demand.

centers (King et al. 2025). Moreover, many load forecasts fail to account for ongoing and future improvements to data center efficiency. These improvements can include advances in server technology, cooling systems, and training and inference algorithms (Nadel 2025; Rebarber 2023).[10]

Third, global constraints in semiconductor chip production also indicate that the electricity needed to power data centers is likely overstated (London Economics International 2025). While utilities project 90 GW of new data center load by 2030, estimates based on **data centers' schedules to begin operation and anticipated shipments of processing chips for data centers suggest only 60–65 GW of load growth** (Cleanview 2025; TD Cowen 2024).

Fourth, utility planners have consistently overestimated electricity demand. Between 2006 and 2023, utility planners, on average, overestimated electricity demand by 8% in their five-year forecasts and by 17% in their 10-year forecasts (see figure 5). This forecast error is even higher for more recent years: forecasts made between 2012 and 2023 were, on average, 23% higher than the actual loads (Sward et al. 2025).

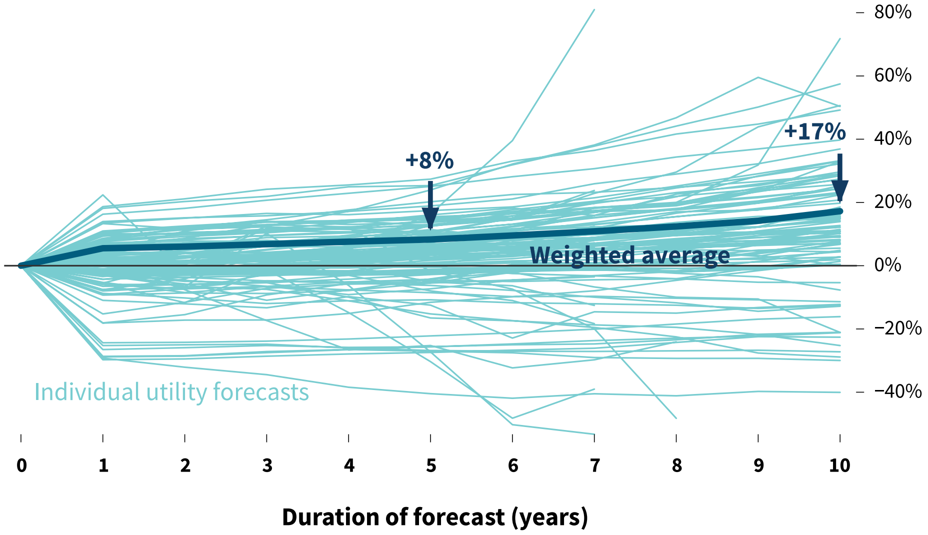

Figure 5. Electricity planning area peak demand forecast error 2006–2023. Positive percentages indicate that utilities overestimated their load. Data sourced from FERC Form 714 by Rocky Mountain Institute (RMI). Figure created by RMI's Sward et al. (2025).

While forecasts consistently show that data centers will be a primary load growth driver, collectively these factors make it difficult to forecast precisely how much load will materialize, even within the next five years. For the reasons listed above, though, it is far more likely that utilities will overestimate anticipated data center loads than underestimate them. They have already begun seeking new generation resources, often gas, to meet data center loads that may not materialize. These actions run the risk of creating stranded assets, which utility ratepayers could be forced to pay for. As laid out in the chapter Advantages of demand-side measures, demand-side solutions provide a more cost-effective alternative to meeting the load that will actually materialize without the risk of having to pay for supply-side resources that will go underutilized.

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[10] More specifically, these advances could reduce the electricity needed per unit of useful output. Replacing the saved electricity with more data center load would erase those energy savings.

Industry

A recent surge in political support, substantial federal investment, and a renewed focus on domestic manufacturing have spurred industrial economic development and accelerated industrial electrification across the United States. Policies such as the Inflation Reduction Act, the Bipartisan Infrastructure Law, and the CHIPS and Science Act were designed to lower financial barriers, provide market signals, encourage private sector investment in clean technologies, and reshore critical technologies.

Since the passage of the Inflation Reduction Act, investments in the U.S.-based manufacturing of clean energy and transportation technologies have reached $136 billion as of Q3 2025—more than a sixfold increase from the $21 billion invested during the same period prior to the law's enactment (Clean Investment Monitor 2025b, 2025a). This influx of capital has fueled the construction and expansion of hundreds of manufacturing facilities. These include semiconductor chip plants, battery production factories, and EV assembly facilities, with battery manufacturing alone more than doubling since 2022, now exceeding 200 GWh annually (Clean Investment Monitor 2025b).

Regionally, hydrogen production and the electrification of oil and gas fields are becoming significant drivers of new demand, especially in areas with favorable policies or abundant resources (e.g., wind, solar) that are suitable for clean hydrogen production (National Renewable Energy Laboratory n.d.). However, the future impact of hydrogen on national electricity demand is uncertain, with limited demand projections that are expected to depend on changes in tax policy or market incentives that could shift rapidly.

The scale of potential industrial demand is substantial. Some analysts suggest that **fully electrifying U.S. industry would add 6,000–10,000 TWh of annual electricity consumption, with 380–900 TWh/year expected to materialize by 2050.** These long-term projections are comparable to the current total national consumption of electricity (approximately 4,300 TWh) and industrial electrification's technical potential even surpasses the projected load from the complete electrification of the transportation sector (Gimon 2023; NEMA 2025; Tsuchida et al. 2024). The growth of the EV battery manufacturing sector is emblematic of this transition—growing from effectively zero consumption in 2020 to a projected 44 TWh per year by 2030 (McGeady 2024).[11] **Utility forecasts project an increase in industrial and manufacturing load by 2030, with perhaps 10 GW more from the oil and gas and mining sectors** (Wilson et al. 2025).

Transportation

Transportation electrification is rapidly emerging as a primary load growth driver due to a variety of factors. These include declining prices for EVs and their batteries, increased range, state and federal transportation policy, and increased public charging access. Load growth in the transportation sector will come from all vehicle types: light, medium, and heavy duty (Murphy et al. 2021; NEMA 2025).

In 2023, the transportation sector consumed 18.3 TWh of electricity, which amounts to less than 1% of total energy consumption in nearly every region of the United States (see figure A3). This is projected to grow to 131 TWh by 2030—nearly a sevenfold increase—exceeding the consumption of data centers in the long run (Hendry and Selvaraju 2023; NEMA 2025). This will come from a combination of personal vehicles, fleets, and heavy-duty vehicles, although light-

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[11] Forty-four TWh is greater than the total electricity consumed by 20 individual states in 2022 and is only slightly larger than Kansas' annual consumption.

duty vehicles will account for more than 75% of total EV electricity demand through 2030 and over 90% by 2035 (PA Consulting 2025).[12]

Unlike data centers and industrial electrification, EVs add demand that is often concentrated in certain hours (e.g., after drivers return home) and locations (e.g., fleet depots, fast charging stations). They can substantially increase peak load, especially when their charging windows coincide with system peak.

However, EVs are among the loads most amenable to load flexibility or "managed charging" (see figure B2). Shifting charging to low-demand hours can reduce peak loads by 0.4–4.5% and decrease distribution upgrade needs by roughly 30% (Borlaug et al. 2024). Increased usage of active or public transit and purchasing more efficient electric vehicles could help as well.

Buildings

Building electrification—including the adoption of electric heat pumps for space heating and cooling, electric heat pump water heaters, and kitchen appliances (e.g., induction stoves)—will become an increasingly important driver of load growth, but its impact through 2030 will be smaller relative to other load growth drivers.

The U.S. residential sector is projected to see a 10% increase in annual electricity consumption, rising from 1,466 TWh in 2023 to 1,600 TWh in 2030, driven by a shift toward electric end uses (Hendry and Selvaraju 2023). Within the residential sector, electrifying space heating is the largest driver of increased electricity demand, followed by water heating. Both contribute substantially to winter peak demand, which is a critical challenge for grid reliability. Unlike traditional summer peaks, which typically occur in the late afternoon, winter peaks often exhibit a dual-peak pattern—one in the early morning (7–9 a.m.) driven by residential heating and water heating, and another in the evening as people return home. These peaks can also persist for extended durations during extreme cold events, posing unique operational challenges for grid operators (Specian et al. 2021).

Commercial building electrification is also expected to take place, but the contribution to electricity demand from these buildings—including office buildings, schools, hospitals, and other large, non-data center structures—is smaller than in the residential sector. While U.S. commercial floor space is projected to grow by roughly 33% between 2020 and 2050, total commercial energy use is expected to rise by only 22%, reflecting substantial efficiency gains from widespread adoption of LEDs, HVAC sensors and controls, and other building technologies that reduce energy use (EIA 2021). Roughly 80% of commercial space heating today is fueled by natural gas, indicating that most buildings still rely on fossil fuels, and adoption of electric heating and other end uses is further slowed by fewer financial incentives and policy programs compared with the residential sector (Energy Systems Integration Group 2024).

However, the significance of building electrification becomes more pronounced at the regional level and in long-term forecasts. New York, California, and New England are already experiencing higher peak demand as policy and market conditions accelerate the transition to electric end uses. For instance, ISO-New England (ISO-NE) is forecasting net electricity consumption across the region to increase by an average of 1.8% per year in part due to more households and businesses switching to electric heat pumps for heating and cooling. Winter

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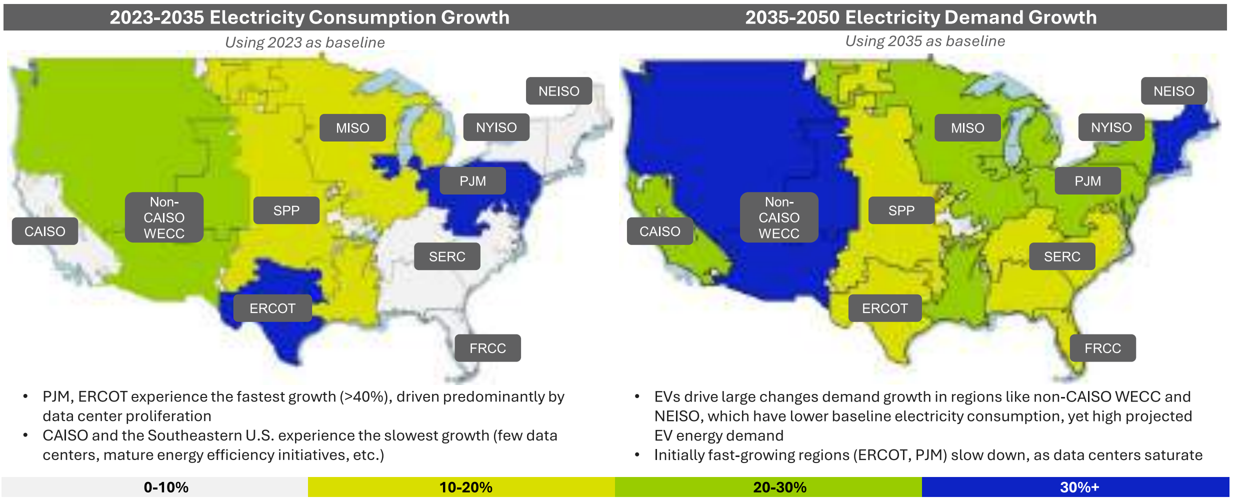
[12] The One Big Beautiful Bill Act sunsets tax credits for new EVs and makes changes to domestic manufacturing requirements, tariffs, and corporate average fuel economy (CAFE) standards. These changes introduce even more uncertainty into these forecasts.

peak demand in ISO-NE is forecast to increase even faster, by an average of 2.9% annually under normal conditions. The different growth rates reflect that winter space heating spikes demand on the coldest days, concentrating heating loads into short time windows (ISO-NE 2025d, 2025a).

Load growth by region

Electricity consumption is expected to rise in every U.S. region, but the drivers, scale, and pace of that growth will vary. The most dramatic near-term increase is projected in PJM,[13] where strong energy demand from data centers is anticipated to sharply elevate electricity use (Chandramowli et al. 2024). In contrast, regions with milder winters and lower heating needs (or higher electric rates)—such as California—may see more modest increases in the need for electricity (see figure 6) (Tsuchida et al. 2024). Policy is a key driver of regional load growth, such as friendly data center policies in PJM and pro-EV policies in California. In the longer term, load growth is projected to be largest in the non-California West and New England, largely due to the more gradual emergence of space heating electrification.



- PJM, ERCOT experience the fastest growth (>40%), driven predominantly by data center proliferation
- CAISO and the Southeastern U.S. experience the slowest growth (few data centers, mature energy efficiency initiatives, etc.)

- EVs drive large changes demand growth in regions like non-CAISO WECC and NEISO, which have lower baseline electricity consumption, yet high projected EV energy demand
- Initially fast-growing regions (ERCOT, PJM) slow down, as data centers saturate

Figure 6. Short- and long-term growth in electricity consumption and demand broken out by grid region. Figure sourced from NEMA 2025.

We expect regional load growth drivers to vary considerably within the next five years, as shown in figure 7. Data centers play an outsized role in PJM; new industrial loads in New York, SPP and the Southeast; and transportation electrification in California, New England, and Florida.

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[13] PJM's service territory encompasses the majorities of New Jersey, Pennsylvania, Delaware, Maryland, Virginia, West Virginia, Kentucky, and Ohio, as well as parts of Indiana, Illinois, and North Carolina.

Figure 7. Percentage growth in regional electricity consumption projected through 2029 relative to a 2024 baseline. Figure sourced from Seiple (2024).

An overview of regional load growth drivers is presented in table 2. The high/moderate/low classifications are intended as a high-level, relative comparison across regions rather than precise forecasts. Categories were assigned based on the expected scale and timing of new electricity demand in each region, drawing from utility IRPs, ISO/RTO forecasts, and reported project pipelines. Drivers classified as "high" represent dominant or near-term sources of load growth shaping current planning decisions, while "moderate" drivers contribute meaningfully but are secondary, and "low" drivers reflect either smaller absolute impacts or growth that is expected to occur later (e.g., mid-2030s and beyond) relative to other regional drivers. In several cases, sectors labeled "low" are still projected to grow substantially over the long term, but their impacts are less immediate or are outweighed by faster-moving demand drivers—particularly data centers and large industrial loads with active interconnection requests or committed projects. More detailed supporting data and references are presented in Appendix A: Load growth forecasts.

Table 2. Regional load growth drivers by sector through 2035

Region	Data centers	Industrial demand	Transportation electrification	Building electrification
Northeast	Low	Low	High EVs projected to consume 8.735 TWh annually by 2034, surpassing heating electrification (ISO-NE 2025e)	High Heating electrification grows from 0.692 TWh in 2025 to 8.049 TWh by 2034, increasing annual electricity consumption by 11% (ISO-NE 2025c); New York expected to become winter peaking by mid-2030
PJM	High Data centers projected to drive ~20% of PJM peak load and 28% of annual energy use by 2040 (PJM 2025a); Northern Virginia alone growing from 1.05 GW in 2024 to >11.7 GW by 2034	Moderate Industrial projects (steel, chip manufacturing, port electrification) add significant load, but less than data centers (PJM, 2025a)	Low	Low
Southeast	High Data centers projected to add ~14–28 TWh annually across Georgia, North Carolina, South Carolina by 2030	Moderate Industrial and large commercial loads add ~15 TWh annually (primarily Duke Carolinas[14]); Georgia plans 22.8 GW of new industrial load, supported by over $100 billion in manufacturing	Low EV adoption and utility investments gradually increase demand; modest relative to other drivers	Low
SPP	Moderate Data centers projected to grow from 17 TWh in 2023 to 62 TWh by 2034 and 98 TWh by 2050; peak load 2–12 GW with state-level variation	Moderate Hydrogen electrolysis demand grows from 0 TWh in 2023 to 235 TWh by 2034, with 241–334 TWh by 2050 under different scenarios; uncertain due to regulations and grid constraints	High EVs and electrified trucks projected to rise from 1 TWh in 2023 to 12 TWh by 2050 (baseline), 73 TWh (moderate), 138 TWh (full electrification)	Low

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[14] Duke Energy Carolinas is a utility that provides electricity in portions of North Carolina and South Carolina.

Region	Data centers	Industrial demand	Transportation electrification	Building electrification
ERCOT	High Data centers account for ~8.8% of statewide electricity use, nearly 30 GW of peak demand by 2031	High Industrial and hydrogen projects add ~25.5 GW of peak load by 2030 (crypto, hydrogen, oil and gas, other industrial)	Low	Low
MISO	High Data centers largest new load, adding 23–37 GW (149–241 TWh) by 2044; Illinois, Indiana, Iowa lead growth	High Industrial/manufacturing electrification adds up to 105 TWh by 2044, supported by policy and new facilities	Moderate EV demand grows 2 GW by 2030; electricity consumption grows from 40 TWh by 2035 to 91 TWh by 2044	Moderate Building electrification adds 30–43 TWh by 2040
CAISO	High Data centers projected to add ~4.5 GW of peak demand by 2035 (14,000–20,000 GWh annually)	Low	High Transportation electrification adds ~4.8 GW of peak demand by 2035 from passenger and commercial EVs	High Building electrification adds ~5.4 GW of peak demand by 2035, supported by all-electric building mandates
Northwest	High Data centers add 1.5–6.2 GW by 2029, electricity use doubles by 2046, contributing to system peaks of 47–60 GW	High Industrial electrification and new manufacturing (chip fabrication, hydrogen) drive significant growth, 1.8–3.1% annual increase through 2040s	Low	Low Building electrification adds ~2 GW of peak demand by 2040; near-term impacts = ~0.5 GW by 2030
Southwest	High Data centers could add up to 29 GW peak demand by 2030 across AZ, NM, NV; annual energy use rises 32–55% from 2025	High Industrial and data center growth drives ~80% of Arizona's 24 GWh annual increase (2023–2038), plus gigawatt-scale EV battery and semiconductor manufacturing in Nevada and New Mexico	Low	Low minimal building electrification

DSM as a solution

Energy efficiency potential

Energy efficiency has proven its value in significantly reducing energy usage since the 1980s. As illustrated in figure 8, U.S. energy use was 76 quadrillion Btu (quads) in 1980, growing 25% to 95 quads by 2024. In the absence of energy efficiency, however, it is estimated that 2024 load would have been 184 quads. This means that energy efficiency met 49% of total energy demand, making it the single largest (though often invisible) energy resource (EIA 2024b; Nadel et al. 2015).[15]

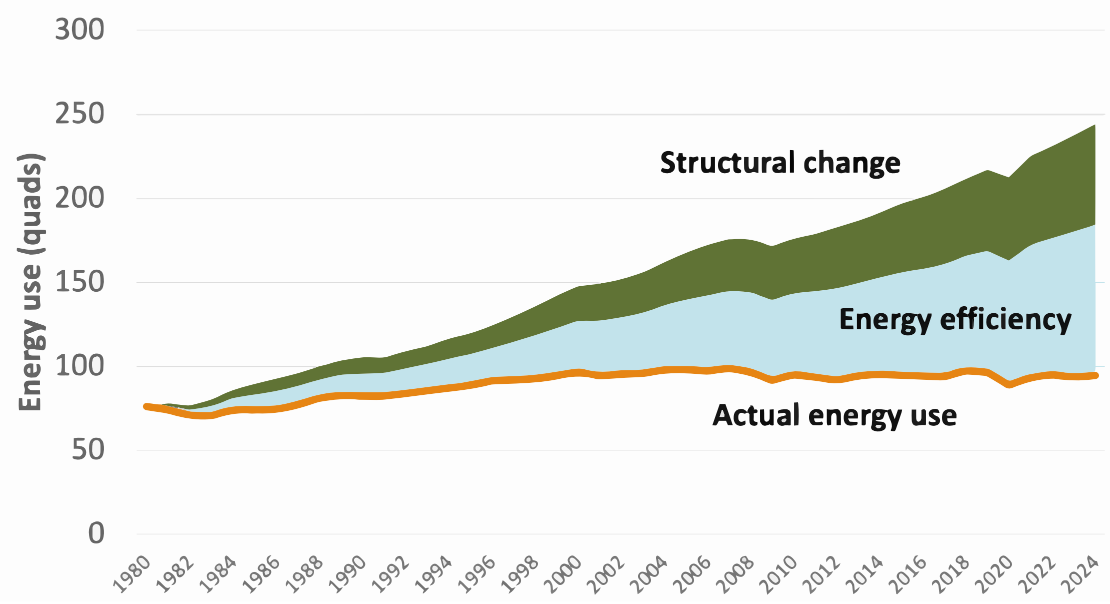

Figure 8. U.S. energy use from 1980 through 2024. Actual energy use is shown by the orange line, while the estimated load that would have occurred in the absence of energy efficiency and structural changes in the economy are illustrated by the light blue and green areas, respectively. Data through 2014 sourced from (Nadel et al. 2015). Additional data generated by ACEEE using EIA data. Load decrements assume a rough 60–40 ratio between energy efficiency and structural change (L. Ungar, director of federal policy, ACEEE, pers. comm. November 17, 2025).

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[15] Structural changes are shifts in the U.S. economy away from some energy-intensive segments like heavy manufacturing.

The amount of energy efficiency “in operation” is a combination of savings achieved by efficiency measures installed this year (i.e., incremental savings) and the savings produced by still-active measures installed in previous years (ultimately referred to as lifetime savings). This enables efficiency savings to stack year over year, even if each year’s incremental savings remain constant. As efficiency measures reach the end of their effective useful lifetimes (e.g., when an efficient appliance stops operating) new measures must continue to be installed to keep the efficiency resource growing. Despite the savings achieved thus far, this speaks to the need for continued investment in solutions like utility energy efficiency programs.

Utility investments in electricity and gas efficiency programs have been cost effectively delivering energy savings for decades. Efficiency program investments tripled between 2006 and 2015, but have increased only modestly since, reaching a value of $8.8 billion in 2023 (see figure 9).

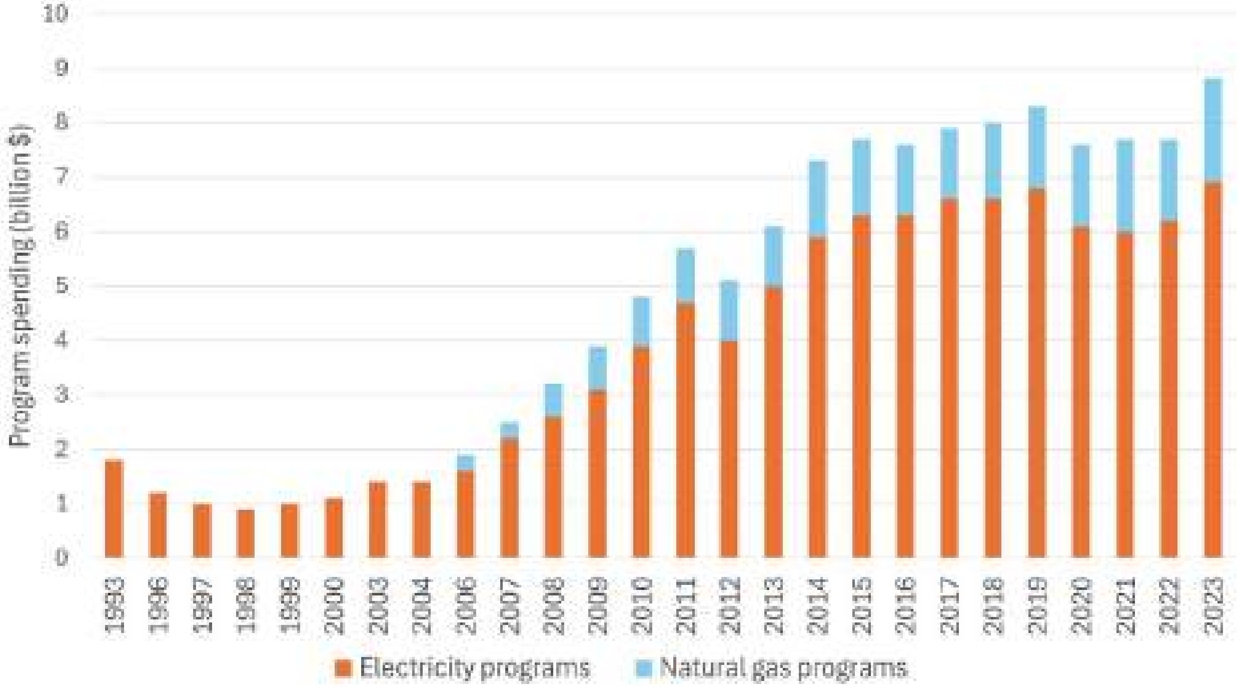

Figure 9. Annual U.S. electric and natural gas energy efficiency program spending. Natural gas spending is not available for the years 1993–2004. Figure sourced from Kresowik et al. (2025).

A wide variety of energy efficiency measures spanning the residential, commercial, and industrial sectors can be utilized to realize energy savings. A summary of those measures is provided here, and a more comprehensive list of measure types and their descriptions are provided in Appendix C: Cost of energy efficiency and load flexibility.

Residential measures focus on upgrading appliances (e.g., refrigerators, washers, dryers), HVAC systems, lighting, and smart thermostats, as well as comprehensive home retrofits, energy audits, weatherization, and educational initiatives. Multifamily programs and new construction incentives ensure efficiency across various housing types, while behavior-based feedback encourages ongoing savings.

Commercial and industrial (C&I) programs emphasize efficient lighting and controls, HVAC upgrades, retrocommissioning,[16] and whole-building retrofits. Motor system optimization stands out as a resource that can cost effectively save 62–104 TWh annually, mostly from fan, pump, and compressor end-use equipment (Rao et al. 2021).[17] Strategic energy management and custom projects address site-specific needs, while specialized programs serve small businesses, restaurants, agriculture, data centers, schools, and government facilities.

Other EE strategies include building energy code compliance, conservation voltage reduction, controlled environment agriculture, cool roofs, efficient transformers, fuel switching, real-time energy feedback, grid-interactive buildings, industrial process improvements, high-efficiency appliances, midstream market transformation, window treatments, and net-zero energy buildings.

Energy efficiency's potential is far from tapped. If all buildings gradually replaced inefficient equipment, appliances, and insulation with efficient alternatives at the end of their useful lifetimes it would reduce up to 742 TWh of annual electricity use in 2030, rising to 800 TWh by 2050.[18] This would be approximately 23% of annual electricity use in 2030. Most of these potential savings result from improvements in space conditioning end-uses, particularly residential heating and cooling, as well as improvements in residential water heating (Langevin et al. 2021).[19]

EPRI finds that utilities' energy efficiency programs "can realistically reduce" annual electricity consumption by over 365 TWh by 2040. This would constitute an 8% reduction in the total estimated annual electricity consumption projected by the U.S. Energy Information Administration (EIA). As shown in figure 10, this potential varies by state, with Florida, the District of Columbia, New York, and Arizona having the highest achievable energy reduction potentials as a percentage of retail sales (Holmes et al. 2019).[20]

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[16] Retrocommissioning involves diagnosing energy consumption in a commercial facility and optimizing its operations to minimize energy waste. Program activities tend to be characterized by tuning or retuning, coordinating, and testing the operation of existing end uses, systems, and equipment for energy-efficient operation.

[17] C&I three-phase motor systems greater than or equal to one horsepower consume just over 1,000 TWh/year, or about 29% of the total electric grid load. Nearly half of motor system electricity consumption is concentrated in just ~3,500 facilities, or 1.5% of U.S. manufacturing facilities.

[18] These numbers reflect demand-side measures' technical potential. These savings account for interactive effects of demand flexibility.

[19] The savings are not geographically homogeneous, with most of the potential lying in the Southeast and Great Lakes/Mid-Atlantic regions. Collectively these regions reach from the eastern seaboard in the east to Michigan, Illinois, Arkansas, and Louisiana in the west, excluding New England.

[20] Technical potential refers to the maximum possible energy savings if all technically feasible measures were implemented. Achievable potential refers to the portion of cost-effective technical potential that can be realistically achieved given policies, funding, market conditions, and consumer behavior.

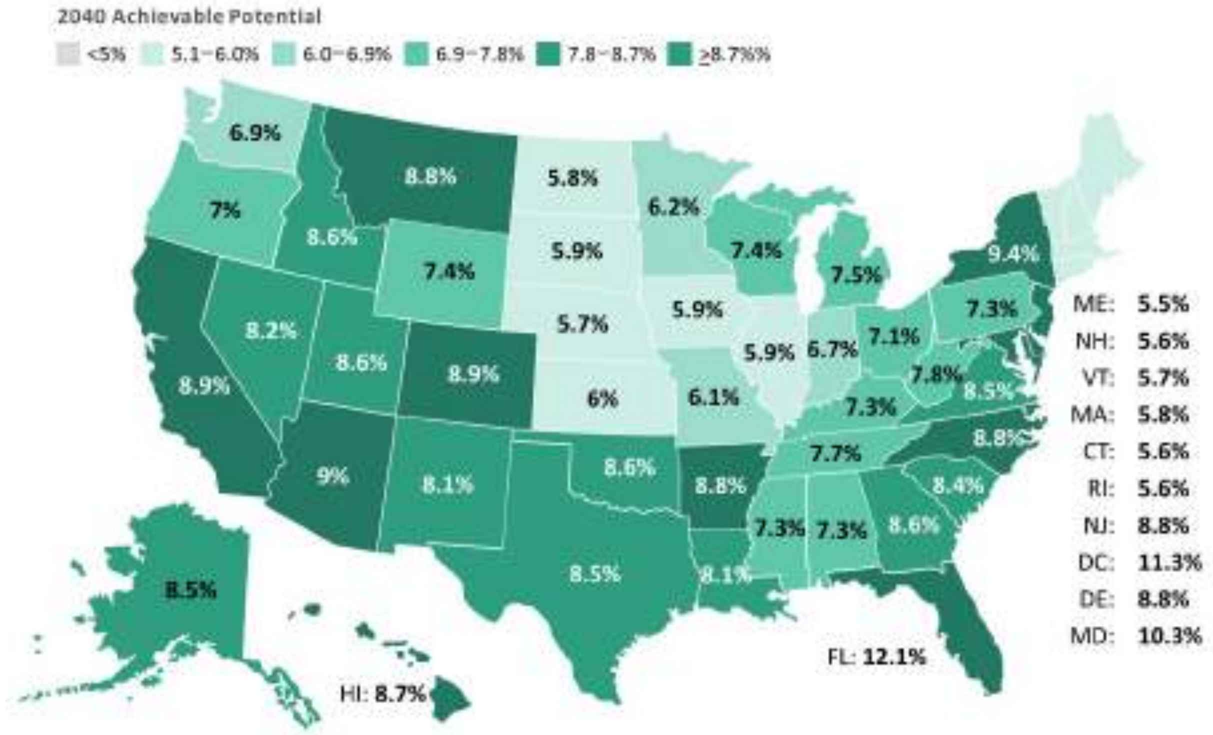

Figure 10. Total energy efficiency achievable potential in 2040 as a percentage of adjusted baseline sales by state. Figure sourced from Tsuchida et al. (2024) from data collected and analyzed by Holmes et al. (2019).

Aggregated at the national level, **by 2040 energy efficiency has the potential to realistically reduce annual electricity consumption in the United States by 8%, with a technical potential 2–3 times that. This is enough to offset about 27% of anticipated energy growth on its own.** Additionally, utility energy efficiency programs simultaneously reduce peak demand when hours of energy savings overlap peak demand hours. We find that these programs achieve on average 0.2 MW of demand reduction per GWh saved.[21] Therefore, in addition to avoiding electricity consumption, **utility EE programs have the realistic potential to reduce about 70 GW of peak demand (with a technical potential of about 150 GW), which is more than forecasted data center capacity expected in 2030.** And these peak reduction benefits are in addition to those provided by DR programs, which are described in the next section.

Load flexibility potential

Demand flexibility can mitigate peak demand in both summer and winter by shifting load to nonpeak hours. This approach takes greater advantage of available headroom, making the most of the grid we already have without the need for additional infrastructure.

In this section, we review load flexibility potential in the United States. Illustrative examples of how this potential manifests for select states and utilities is provided in Appendix B: Select state load flexibility potentials. From both national and local perspectives, multiple independent analyses show that load flexibility can help meet the loads of the future while avoiding the expense of building new grid infrastructure.

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[21] See **Appendix C: Cost of energy efficiency and load flexibility** for details.

As of 2017, load flexibility programs were delivering about 60 GW of capacity (equivalent to about 7% of the nation's peak-coincident demand) with 18 GW of that coming from residential and commercial buildings (Baldwin 2024; Hledik et al. 2019) (see figure 11). The capacity coming from retail programs was about 32 GW in 2017 and 29.2 GW in 2021, indicating no substantial change in the procurement of that resource (FERC 2023). Deloitte found that residential distributed energy resource (DER) capacity (i.e., distributed generation, storage, and flexible demand) met 46 GW of peak demand in 2023 (Thomson et al. 2024).

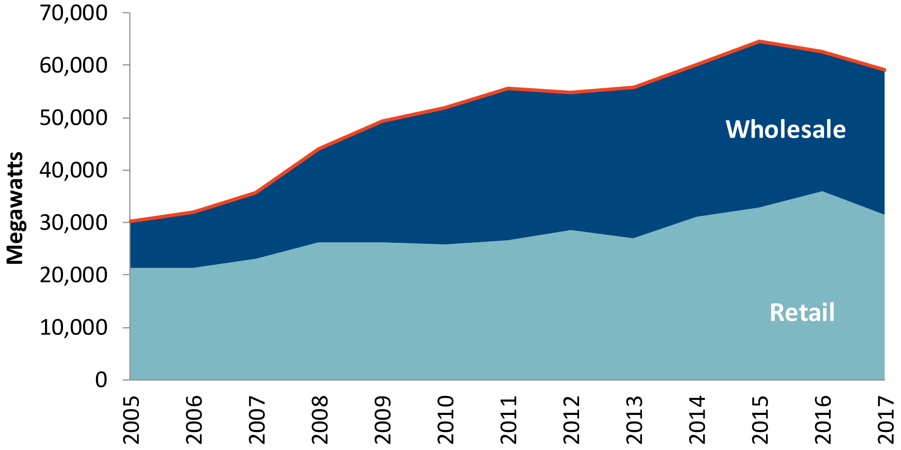

Figure 11. Total U.S. load flexibility peak reduction capability by year. Retail and wholesale DR data sourced from EIA-861 and FERC Assessment of Demand Response and Advanced Metering reports (2006–2018), respectively, by the Brattle Group. Figure created by Hledik et al. (2019).

The stagnation in DR capacity that started around 2015 can be attributed to a number of factors. These include increasingly stringent wholesale market participation rules that restrict aggregator participation, low capacity market prices that undervalue DR, utility business models that favor supply-side investments over demand-side programs, insufficient funding for enabling grid-interactive efficient building (GEB) technologies, perceived complexity of executing DR, perceived lack of trust in the DR resource, and projections of excess peaking capacity.

Still, there is huge growth potential for load flexibility programs, as only 6% of U.S. energy consumers participated in a retail DR program in 2024 (EIA 2024a). The U.S. Department of Energy (DOE) concluded that achievable peak reduction via demand flexibility from residential and commercial buildings **could be as large as 116 GW by 2030** (Satchwell et al. 2021).

In 2019, the Brattle Group concluded that there was **about 200 GW of load flexibility potential** in the United States by 2030 (Hledik et al. 2019). However, their analysis did not consider the full flexibility potential of data centers, batteries, or EVs, which makes the 200 GW potential an underestimate. That said, six years have elapsed since the 2019 study and DR growth has been limited in that time. As such, it is not realistic to expect all that potential to be realized by 2030, though reaching that level by 2035 remains a possibility (R. Hledik, principal, Brattle Group, pers. comm., April 21, 2025).

Other researchers have looked at the total potential of demand-side resources in combination and arrived at consistent conclusions. Langevin et al. find that the combined **technical potential of EE and DR to reduce daily net peak load is 181 GW in 2030 and 208 GW by 2050,** with at least 59 GW and 69 GW, respectively, of the peak reduction being dispatchable (Langevin et al. 2021). According to data collected from the Rocky Mountain Institute (RMI) (see figure 12),

EE and DR have the potential to cover 113 GW (over 40%) of needed peak capacity in 2034, with 60 GW coming from DR (Cohen et al. 2025; Martin and Brehm 2023; Numata et al. 2025). Other estimates include **flexible residential DER capacity growing to over 96 GW by 2032** (Guidehouse Insights 2023) and **flexible demand of about 107 GW in 2035** (Thomson et al. 2024).[22]

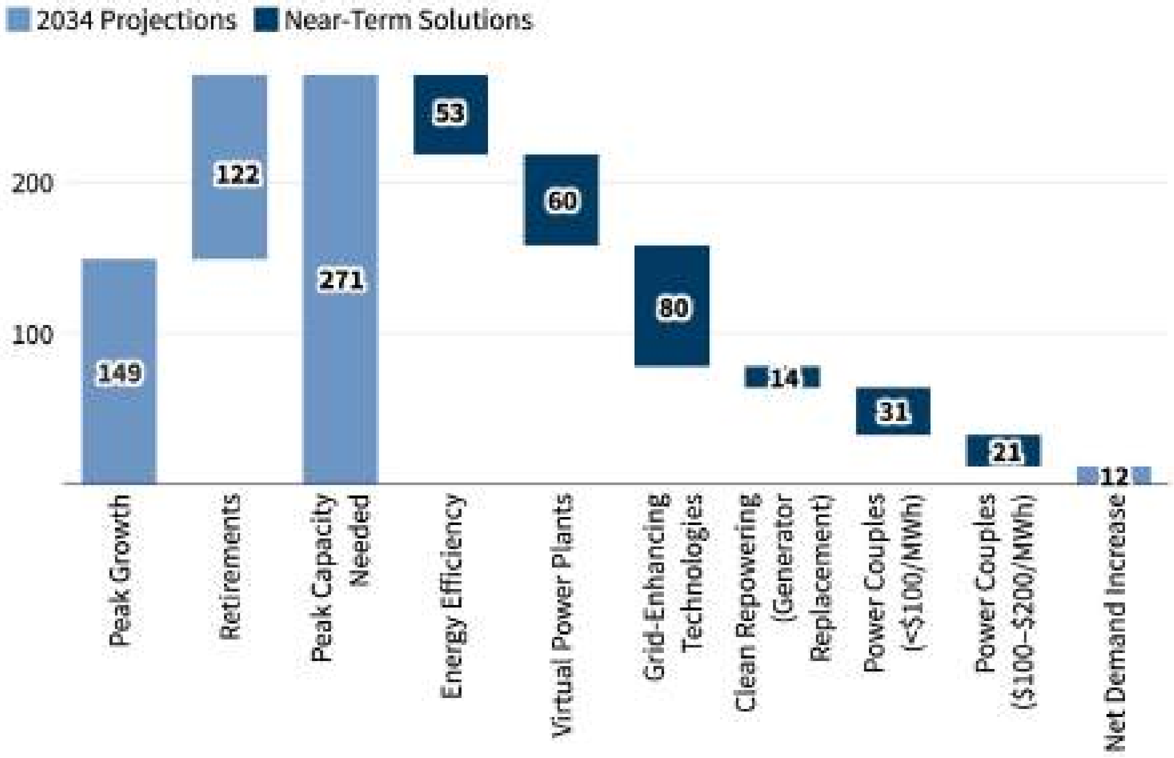

Figure 12. Potential 10-year peak demand growth and near-term solutions. Vertical axis measured in GW. Figure sourced from Cohen et al. (2025).

While estimates of load flexibility potential differ based on modeling assumptions, **most experts agree that there is about 60–200 GW of DR potential available in the United States within the next decade.** To put those values in context, **this load reduction potential is roughly 1–2 times larger than the most aggressive projections of total data center capacity** expected to be on the grid in 2030 (see table 1).

Advantages of demand-side measures

Load growth is one of greatest challenges the electric grid has faced in decades, one that will doubtless require a variety of solutions. To date, many states and utilities have defaulted toward supply-side resources to meet the need due in part to a bias toward capital investments in cost-of-service business models. A better alternative is to allow all energy resources (supply and demand side) to compete fairly to determine their optimal combination.

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[22] Analysis assumes a 1.5°C decarbonization scenario and storage that could be harnessed from vehicle-to-grid and hot-water heaters.

In doing so, utilities and policymakers should consider the multiple advantages demand-side resources offer including reduced cost, faster deployment speed, ratepayer protection, and lower environmental footprint. In this section, we describe those advantages that utilities, regulators, and consumer advocates should leverage in support of a cleaner, less expensive, and more reliable energy system.[23]

Cost

An analysis of the largest U.S. utilities' energy efficiency programs reveals that in 2024 the average cost of energy efficiency was $23.20/MWh with a median cost of $20.70/MWh.[24] A comparison of energy efficiency costs to other generation resources, provided in figure 13, demonstrates that EE remains the least-cost energy resource by a significant margin.[25]

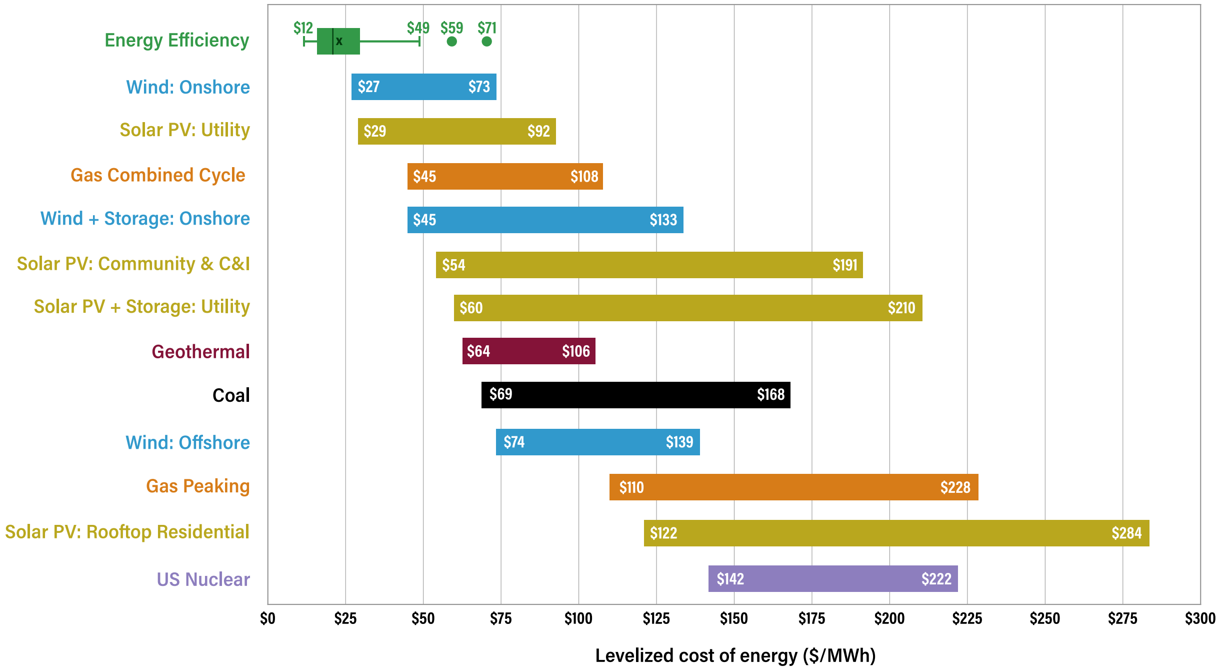

Figure 13. A comparison of the levelized cost of energy efficiency and other supply-side resources. Vertical line and "X" represent the median and mean costs of energy efficiency, respectively. Cost data for supply-side resources generated by Lazard (2024).

Figure 14 places this finding in context. The average wholesale price of electricity in 2025 is estimated to be $43.90 per MWh in summer. By itself, this is approximately twice the cost of the energy efficiency resource. Moreover, these wholesale costs do not include power distribution expenses, which are reduced by energy efficiency. They also do not account for additional utility costs (e.g., administration) that ultimately make their way into the retail price of electricity. In total, that means that energy efficiency's comparative advantage as illustrated in figure 13 is likely an underestimate of its relative value.

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[23] Demand-side measures also deliver air quality and public health benefits. We do not address these in detail in this report and direct the reader to other references on the subject (e.g., ACEEE 2025; EPA 2024; Kamana-Williams et al. 2025).

[24] These costs are inclusive of all utility energy efficiency-related expenses including administration, marketing, and evaluation and measurement.

[25] It is worth noting that efficiency retains this status despite improvements in energy building codes and the retirement of utility efficient lighting programs, both of which have been perceived as making the achievement of additional energy savings more difficult.

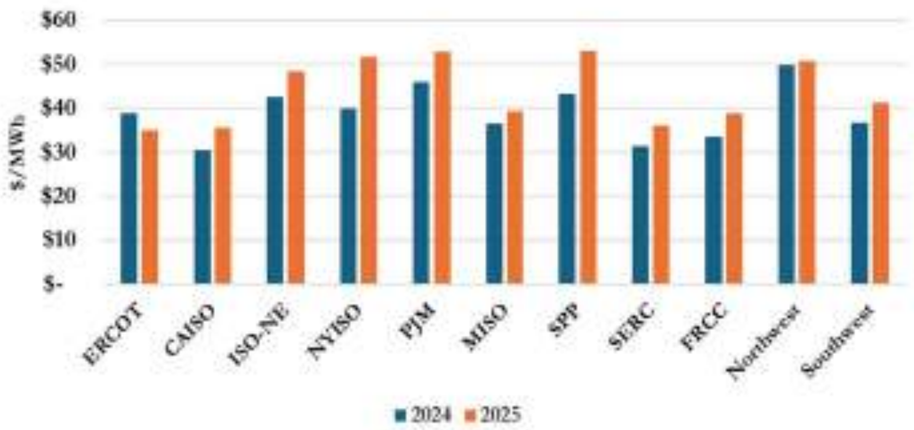

Figure 14. Summer average wholesale electricity prices at selected hubs in 2024 and 2025. Prices in 2025 are a projection provided by EIA. Figure sourced from FERC (2025c) .

A similar cost advantage exists for utility-administered load flexibility programs. Table 3 summarizes the cost of supply-side resources for peak demand reduction, while table 4 does the same for 10 of the nation's best-performing DR programs. We find that the best-run utility DR programs are capable of achieving peak demand reduction at a lower cost than any supply-side resources. For a detailed explanation of how the costs of energy efficiency and load flexibility were derived, reference Appendix C: Cost of energy efficiency and load flexibility.

Table 3. Range of effective costs of load reduction from supply-side resources

Generation type	Effective cost, low ($/kW-year)	Effective cost, high ($/kW-year)
Gas peaking	$51.72	$85.63
Gas combined cycle	$65.63	$113.13
Solar photovoltaic (PV) + storage–utility	$72.44	$119.84
Solar PV–utility	$95.89	$146.74
Wind+storage–onshore	$104.19	$153.85
Solar PV–Community and C&I	$153.08	$317.03
Coal	$167.03	$364.16
Geothermal	$219.89	$281.00
Solar PV–rooftop residential	$294.84	$505.43
U.S. nuclear	$364.23	$531.28
Wind–onshore	$399.02	$607.84
Wind–offshore	$1088.24	$1659.80

Values derived based off data calculated by Lazard (2024).

Table 4. Costs of utility load flexibility programs administered in 2024 per kW of peak demand reduction

Utility	Cost of DR ($/kW-year)
Arizona Public Service Co.	$6.62
DTE Electric Company	$17.36
MidAmerican Energy Co.	$25.64
Salt River Project	$25.76
Entergy Texas Inc.	$35.97
CenterPoint Energy TX	$38.39
Georgia Power Co.	$39.96
Oncor	$41.20
PacifiCorp	$44.13
Duke Energy Carolinas	$53.43

To illustrate just one example of how DR programs can deliver cost savings, consider the analysis of California vehicle-to-grid (V2G) programs provided in figure 15. **V2G programs allow EVs to bidirectionally interact with the grid, which includes both drawing energy from the grid and feeding energy back.** These programs are projected to save over $10 billion per year by 2045 with just medium program enrollment. These savings come from reducing the need to build new thermal generation (green bars), reducing the need to procure additional energy storage (gray bar), and providing timing flexibility that allows for the use of more renewable energy (blue bars) (Houston et al. 2025).

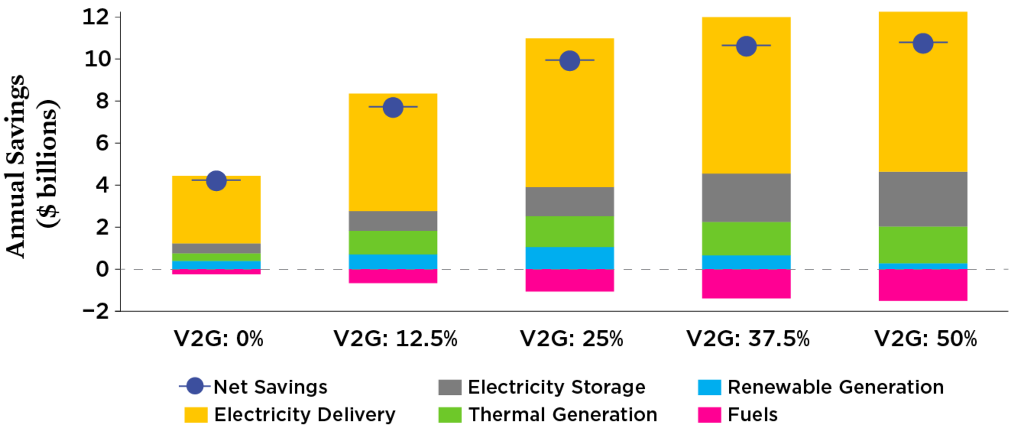

Figure 15. California electricity system savings by category in 2045 through vehicle-to-grid enrollment. Scenario pictured indicates medium enrollment in which 50% of level 2 loads are enrolled in the vehicle-to-grid integration, that is, V2G of 0% is the same as V1G (the management of when EVs charge without any discharge back to the grid) while V2G of 50% indicates all enrolled customers participate in V2G (as opposed to V1G). Annual savings values above zero reflect savings from avoiding the buildout of extra infrastructure relative to the baseline scenario with only time-of-use rate adoption. Values below zero represent additional costs from fuels like electrolytic hydrogen and biofuels. The dark blue dot on each column shows the net savings. Figure sourced from Houston et al. (2025).

There are other unique factors at play that complicate this cost picture for supply-side resources over the next several years. First, new generation capacity is expensive and becoming more so. Costs for construction materials like steel, aluminum, copper, timber, and cement have jumped 40% in the past five years (FRED 2025). PJM has already seen its capacity costs increase by a factor of eight (to $16.1 billion) since 2023, almost entirely due to data centers (Independent Market Monitor for PJM 2025; PJM Inside Lines 2025).[26]

The build out of generation resources often requires significant investment in the transmission and distribution systems. The transmission system is needed to transport electricity, including renewable energy that is often produced far from load centers, across regions. Distribution system upgrades are also needed, especially in locations with disproportionate load growth due to increased installation of electric vehicle chargers and heat pumps. This is on top of distribution system investments that have already increased over $30 billion since 2003 (see figure 16).

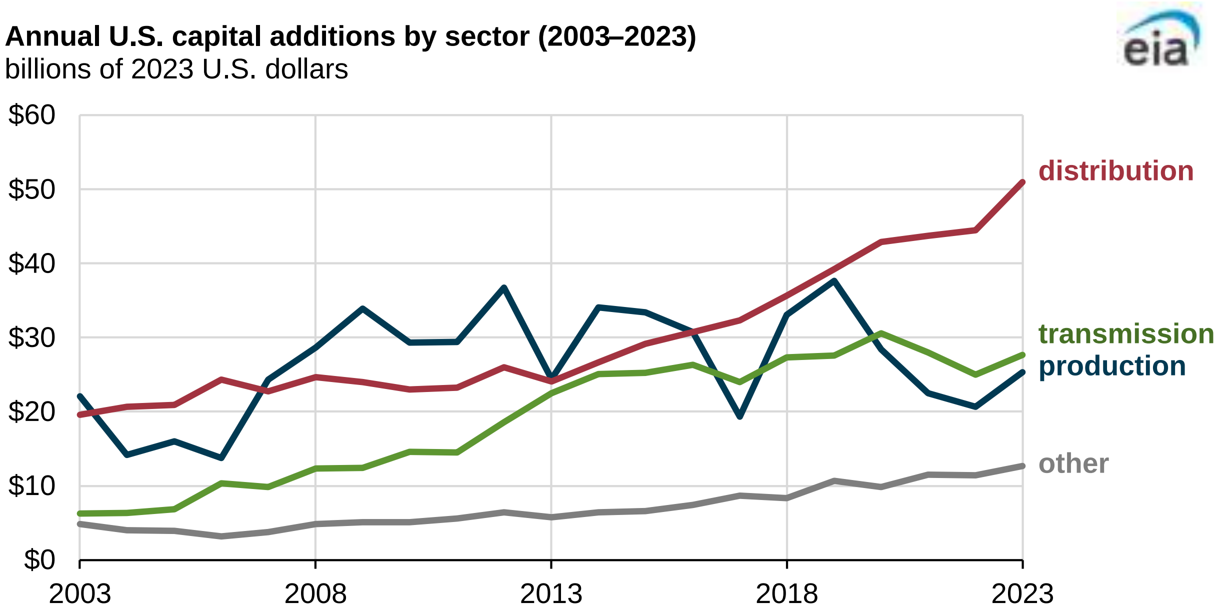

Figure 16. Annual U.S. power system capital additions by sector. Figure sourced from EIA (2024c).

Second, a global shortage of power equipment like turbines and transformers is likely to slow the development of new power plants. Wait times for new turbines have increased from two years to five years or more, a delay that has contributed to a cost increase for building new gas plants to as much as $2,800 per kW (Rathi et al. 2025).[27] Even if power equipment is available, recent changes in trade policy and tariffs introduce considerable price uncertainty into the components needed to install and interconnect supply-side resources (Rathi et al. 2025). Many components such as turbines are sourced from abroad, and tariffs could considerably increase their costs beyond what is projected in current estimates.[28]

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[26] PJM estimates customer utility bills could increase 5% as a result (St. John 2025a).

[27] This is several times higher than the normal range of capital expenditure (CapEx) costs for new gas peaking ($700–1,150 per kW) and gas combined cycle capacity ($850–1,300 per kW). See table C4 for additional details.

[28] For example, among 2024 imports Mexico supplied 39% of high-voltage transformers, Canada supplied 20% of high-voltage switchgear and 100% of utility poles, and China supplied 54% of low-voltage transformers. Canada also supplied 63% of the entire U.S. wind blade market (Crooks 2025).

Third, the cost to deliver power to customers has been increasing across the board. Power prices have been rising at more than twice the rate of inflation and are projected to increase 19% over the next three years (Chandramowli et al. 2024; Horsley 2025) Costs for electric infrastructure like transformers, switchgear, wires, and cable have increased up to 250% since 2018 (see figure 17) (Lubershane 2025). Distribution system expansion costs have increased 150% in the last 20 years and are now on par with generation and transmission expenditures combined (EIA 2024c).

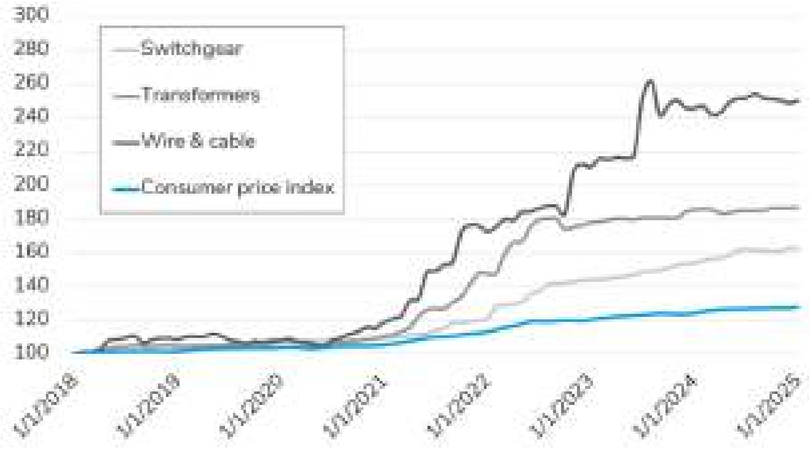

Figure 17. Producer price indices for critical power system equipment. Data from St. Louis Federal Reserve FRED database, indexed to January 1, 2018. Supporting data and figure credit to Lubershane (2025).

Considered in combination, distribution system costs—including new or upgraded substations, transformers, and power lines—are likely to be among the largest avoided by DSM. Kevala, an electrification modeling firm, estimates up to $50 billion in traditional electricity distribution grid infrastructure investments will be needed by 2035 just for California's three investor-owned utilities (Kevala 2023). If demand flexibility is used to manage electric vehicles' loads, that cost could be cut in half (Abhishek and Steinmetz 2024).

Demand-side measures leveraged to avoid these expenses are often referred to as "nonwires alternatives" (NWAs) for their ability to meet energy system needs without additional transmission and distribution (T&D) infrastructure. These projects have been in operation for over a decade and provide many advantages. They can increase utilization of the existing grid without the need to build new infrastructure, which spreads fixed grid costs more broadly and eases pressure on other ratepayers. They also provide the flexibility to implement solutions incrementally as load grows (avoiding large up-front costs), and can accelerate deployment of new loads relative to years-long construction timelines (Brancucci et al. 2025; E4TheFuture et al. 2018). A prime example of NWAs in action is the Brooklyn-Queens Demand Management Program, which used demand-side measures to avoid over a billion dollars of infrastructure investments (U.S. DOE New York–New Jersey CHP Technical Assistance Partnership 2019).

Taken together, **the inflated cost of building and connecting new supply-side resources will certainly compel utilities to seek significant rate increases,** a conclusion supported by credit rating agencies (Fitch Ratings 2024; S&P Global Ratings 2025). These anticipated rate increases amplify the value of energy-saving measures, which help both efficiency program participants and utilities avoid those increased costs.

Speed

The economic potential of data centers has driven companies to interconnect their loads to the grid as quickly as possible. Data centers' limited geographic distribution—in 2023, 80% of data center load was located in just 15 states—demonstrates that not all locations are equally amenable to their development (EPRI 2024a). Developers look for features like access to the national fiber-optic cable backbone, a skilled workforce, end-use customers, low-cost operating environments, and energy resources that will allow their data centers to get up and running with minimal delay. In the battle to win the AI race, speed is paramount, and demand-side measures provide the fastest way to start meeting energy needs.

The rapid load growth occurring in the United States has only appeared in forecasts over the last few years. This recent change has been rapid enough that production of supply-side energy technologies has not yet had time to scale up to meet that need (Stapczynski et al. 2025). As a result, there are significant supply chain delays on these technologies. Large gas turbines are manufactured by just three global companies and are likely to take 5–7 years to be delivered (DiGangi 2025; Stansbury et al. 2025). In short, we cannot build generation, transmission, and distribution infrastructure fast enough to meet the economic desires of large load customers.

Even when power equipment is available, long interconnection queues remain a disadvantage of supply-side resources. Solar and wind projects wait five years on average to get interconnected to the grid, a delay large enough to compel around 80% of queued capacity to withdraw before connection (Gorman et al. 2025). The wait for transmission lines is even longer, often taking a decade or more (NERC 2024). Upgrading and expanding the distribution system can also involve waiting years to procure equipment and work out land use and permitting issues. In California, for example, upgrading and building a new substation now takes four and nine years, respectively (California Public Utility Commission 2024).

A characteristic timescale between when a large load customer indicates an interest in interconnecting to the grid and when their interconnection is complete and ready to energize has historically been around five years. This time is required to work through issues related to transmission studies, permitting, and network upgrades. Environmental impact statements often take two years or more to complete (Council on Environmental Quality 2025). Dominion Virginia, for example, expects the time to connect large data centers to increase to 4–7 years due to a surge in demand and infrastructure bottlenecks (Saul 2024). Demand-side resources avoid infrastructure upgrades and require no additional permitting, which can significantly cut down the wait time to energize.

In comparison to generation, energy efficiency technologies are comparatively domestically based, and need to be installed by a local workforce. Most energy savings are facilitated either by purchases that customers make for themselves in the market or through utility energy efficiency programs, the latter of which are quite mature. Because utilities have been running demand-side programs for decades, they are experienced in delivering these benefits to customers and the grid. Moreover, **energy efficiency programs have the potential to scale up quickly with adequate policy support. The fastest-growing programs of the last decade have an average annual growth rate in lifetime energy savings of about 43% over a triennium, while select programs have doubled year over year.**[29] Monetized virtual power plant programs have grown by more than one-third in the past year (Wood Mackenzie 2025).

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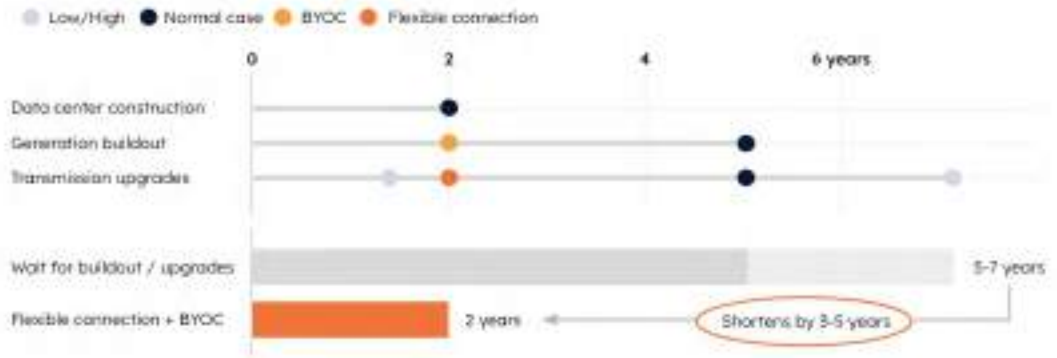
[29] Growth is measured in lifetime energy savings achieved by measures installed in comparison years. A sample of fast-scaling programs is provided in **Appendix C: Cost of energy efficiency and load flexibility**.

In December 2025, the first publicly available study to combine real utility transmission system data, system-level capacity expansion modeling, and site-level capacity optimization evaluated how specialized capacity arrangements can accelerate data center interconnections. The researchers found that a 500-MW data center that makes use of “flexible connection” and brings to the table its own capacity can reach full operation 3–5 years faster than traditional interconnection processes (Brancucci et al. 2025). Including energy efficiency and load flexibility as a complement to this “bring your own capacity” (BYOC) framework can support the faster grid connection illustrated in figure 18.



Normal and high cases assume major transmission upgrades (e.g. new 230 kV or higher lines, significant reconductoring of lines) are required. Low case assumes extension of MV transmission and/or development of a new or retrofitted substation. Normal case for generation buildout assumes a new generation resource must navigate the PJM interconnection queue (start to finish).

Sources: U.S. Department of Energy Transmission Impact Assessment, Bloomberg, primary industry interviews

Figure 18. Modeled timelines for data center grid connection under standard processes (gray) and under a flexible connection and BYOC framework (orange). In this context, “flexible connection” refers to an arrangement where a data center receives firm capacity (uninterrupted grid power) and conditional firm service (access to power when it is available) by using its own capacity, including demand flexibility, during times of grid stress. Modeling conducted and figure produced by Brancucci et al. (2025).

An additional advantage of demand-side measures is that they can be targeted to the regions where load growth relief is needed most. Moreover, there is no need for these resources to enter lengthy interconnection queues before they can be approved for installation and deployment. The additional headroom provided by these resources also lightens the lift that generation needs to meet for very large loads like those from electrifying industrial facilities and data centers.

Taking advantage of available headroom

Even though load growth is pushing up against the limits of the grid, this only happens a small percentage of the time. Load flexibility, when strategically deployed during those hours, can open up additional headroom that would otherwise need to be met by expensive supply-side alternatives.

Figure 19 depicts 22 balancing authorities representing about 95% of the country’s load. Their load factors (average load divided by peak load) range between 43% and 61% with an average load factor of about 53%. In other words, for any given hour, on average, about half of our existing generation and transmission infrastructure is unused.

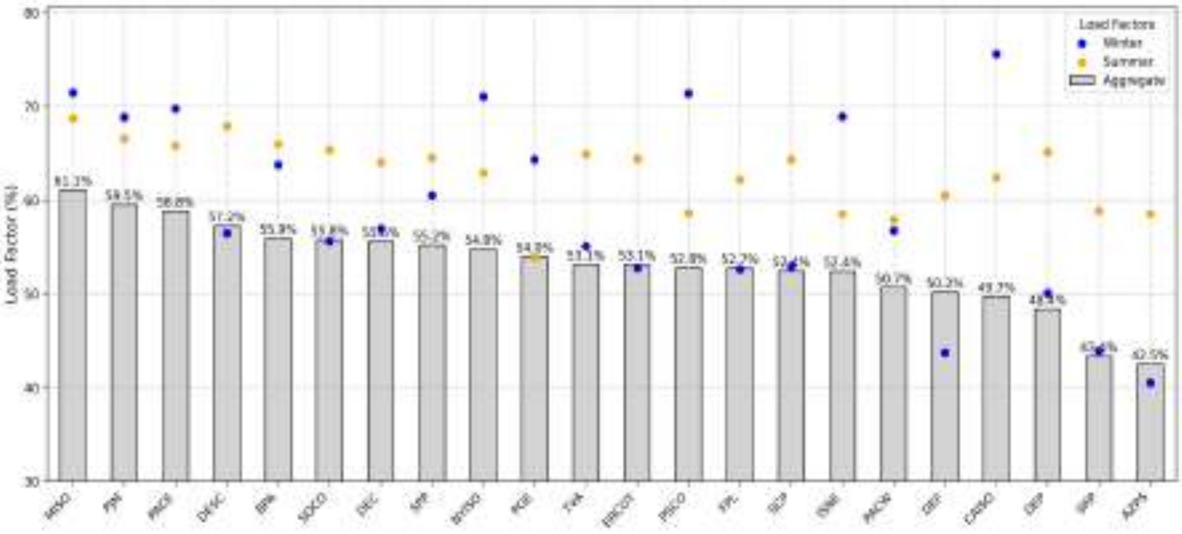


Figure 19. Load factor by balancing authority and season, 2016–2024. Figure sourced from Norris et al. (2025).

Figure 20 offers a view of how many hours per year a grid region experiences peak demand conditions. The top 20% of peak demand occurs in less than 10% of the hours, while the top 10% of demand occurs in just a small handful of hours. In other words, our entire power system is designed to accommodate very occasional system peaks, which currently occur during extreme weather events, either during extreme heat waves or cold snaps (especially on cold winter mornings).

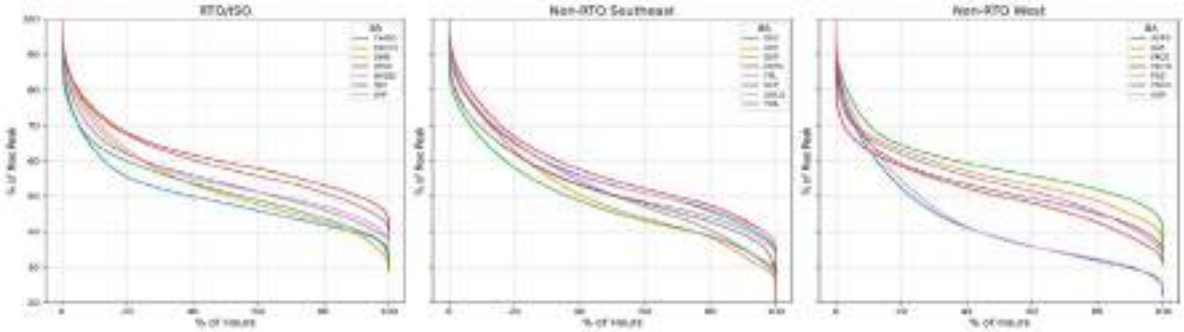


Figure 20. Load duration curves by balancing authority, 2016–2024. Figure sourced from Norris et al. (2025).

This suggests that significant additional headroom on the existing grid can be made available if load flexibility is used to shift loads during peak periods to off-peak periods. Not every load is amenable to load shifting (e.g., medical equipment, air traffic control systems, some industrial processes), but a great many are, including many responsible for projected load growth. These include

- Cryptomining (not time sensitive, very flexible)
- Thermal space conditioning (usually for some fraction of an hour during peak)
- Water heating (minimal customer impact)
- Electric vehicle charging (highly flexible through managed charging)
- Data centers (especially if uninterruptable power supplies and backup storage are present)

Grid operators currently ensure reliability by assuming 100% of peak load is being drawn, then applying contingencies and local stress cases. In combination, this is worst-case scenario planning for potential system overloads. The outcomes of these modeling exercises can trigger substantial, expensive grid investments and possibly stranded assets.

By comparison, load flexibility can open up significant headroom without the need for much additional infrastructure. Figure 21 illustrates how much additional headroom can be opened up by curtailing a small fraction of the overall data center load. For example, curtailing just 0.5% of data center load would enable 98 GW of system headroom across those 22 balancing authorities.[30] Curtailing just 0.25% of data center load would enable 76 GW of headroom. To put that in perspective, 98 GW is enough headroom to accommodate 490 data centers, each rated at 200 MW, or 98 data centers, each rated at 1 GW. This is also enough headroom to cover approximately 1–4 times forecasted data center capacity through 2030 (see table 1) (Norris et al. 2025).

Moreover, curtailment only means that during a limited number of hours per year, the load would be unserved by the electric grid. The portion of the load could either be shed, shifted to off-peak hours, or met with backup energy resources like battery storage or onsite generators. Data centers are often considered uninterruptable loads, which is a main reason they often, if not always, contain uninterruptable power supplies that turn on to provide emergency backup power to critical equipment when grid power fails. Utilizing this existing infrastructure can help meet energy needs without triggering expensive grid upgrades.

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[30] For example, 0.5% load curtailment means that 0.5% of the new load's maximum potential annual energy consumption is curtailed during the highest load hours.

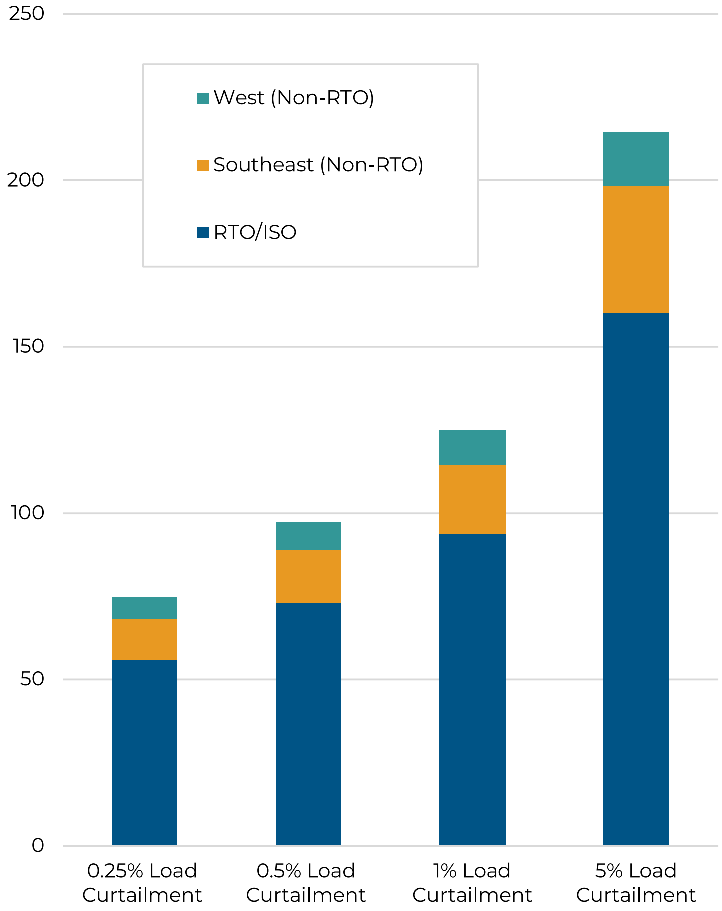

Figure 21. Headroom enabled by load curtailment thresholds. Vertical axis is measured in GW. Figure sourced from Norris et al. (2025).

Meeting climate goals

Limiting global warming to 1.5°C requires that greenhouse gas (GHG) emissions peak no later than 2025 and decline 43% by 2030 (UNFCCC n.d.). While it is becoming increasingly unrealistic for this target to be met, averting the worst effects of climate change requires that we scale down the use of fossil fuels as quickly as possible. **Demand-side measures provide an attractive, zero-carbon alternative to gas and coal.**

Zero-carbon generation sources—such as solar, wind, hydroelectric, nuclear, and geothermal—are essential components of the solution to explosive load growth. However, unlike demand-side management these generation resources introduce additional complexities, including delays in procuring generation equipment, timelines for siting and permitting transmission infrastructure that can last on the order of a decade, and lengthy wait times for interconnecting clean generation to the grid.

As a result, many new loads are defaulting to installing massive amounts of new gas generation and extending the lives of coal plants that would otherwise be retired. These developments are expected to increase U.S. carbon dioxide emissions by 2% in 2025 alone and will lock in significant sources of emissions for the lifetimes of the plants (EIA 2025a). Bloomberg New Energy Finance estimates that meeting data center load with fossil resources through 2035 is projected to increase cumulative carbon emissions significantly—by an amount equal to about 10% of 2025's total global emissions—with the United States and China being the largest contributors by far (Hostert et al. 2025).

An RMI analysis of utility integrated resource plan (IRP) updates in 2025 Q3 finds that not only are utilities not on target to meet the International Energy Agency's (IEA) Net Zero Emissions (NZE) by 2035 scenario,[31] load growth is driving them even further away from their previous targets (see figure 22). These factors will make it considerably harder to reach state and global climate goals and consign the planet to otherwise avoidable negative outcomes of climate change.

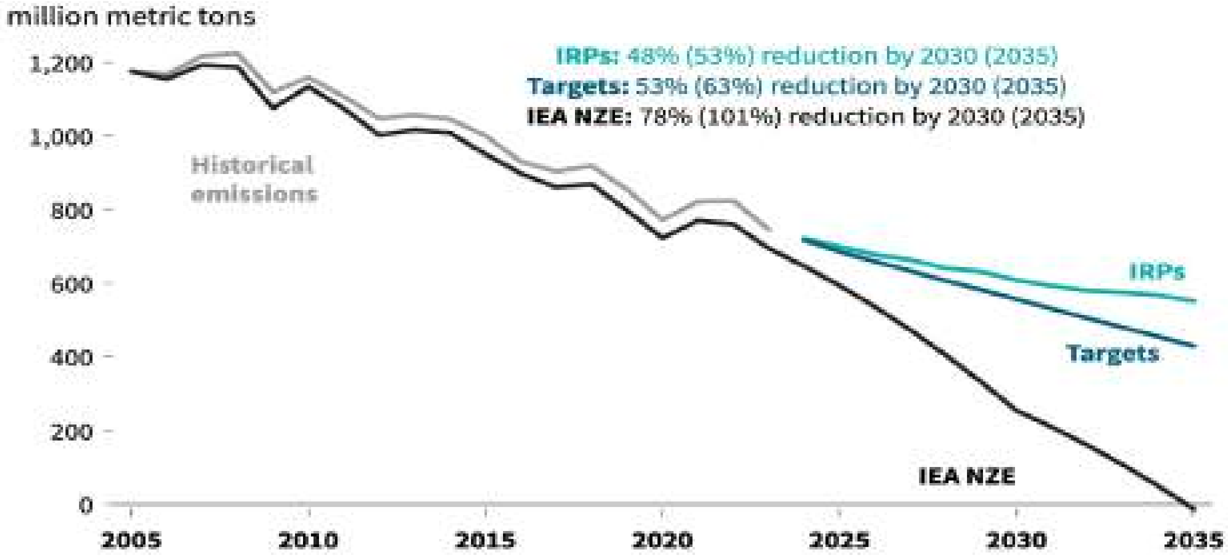

Figure 22. Projected emissions from IRPs, utility targets, and the IEA NZE scenario. Data gathered and figure produced by RMI through their Engage & Act platform (Rea 2025; RMI 2025).

We are also seeing increases in wind and solar curtailments as the grid decarbonizes. In California, for example, there were 3.4 million MWh of curtailed utility-scale solar and wind output (EIA 2025b). Rather than letting this cheap, clean energy essentially go to waste, it can be used to charge storage systems that can subsequently be relied upon to discharge a fraction of that energy during peak periods.[32] In a region like CAISO, where battery capacity is increasing quickly (from 8.0 GW in 2023 to 11.6 GW in 2024), this becomes even more realistic (EIA 2025c).

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[31] The IEA NZE is pathway toward net-zero energy-related CO_2 emissions by 2050, which would limit global warming to around 1.5°C.

[32] This approach assumes curtailment is not the result of transmission constraints.

These findings align with the *climate-forward efficiency* framework for equitably aligning energy efficiency and decarbonization goals within state and utility energy portfolios. We refer the reader to *The Need for Climate-Forward Efficiency* and *A Roadmap for Climate-Forward Efficiency* reports, which in combination justify why energy efficiency programs need to evolve to address the climate crisis and provide recommended steps for legislators, utility regulators, utilities, and other state agencies to maximize EE's GHG mitigation potential (Specian et al. 2022; Specian and Gold 2021).

Protecting retail customers

Rapidly rising electricity bills have created an affordability crisis in the United States, particularly for low-income households. There is a pressing need to drive down electricity costs, and energy efficiency and load flexibility are ideal tools for protecting ratepayers against the changes induced by large load growth. Energy efficiency as a grid resource is almost always required to pass cost-effectiveness screens. This means utilities only procure the resource if the benefits it delivers to the utility, program participants, or society exceed the costs.

The magnitude of new electric load being added to the grid by single customers, especially from data centers, is unprecedented. To their credit, some utilities are negotiating arrangements where data centers would be singularly responsible for the costs to interconnect their facilities to the grid.

However, there are other cases in which the costs of grid upgrades follow the conventional model of socializing the upgrade costs across the entire rate base. While this makes sense in the case of marginal load increases spread across a large number of customers (e.g., as in the case of heating electrification), the model is not appropriate for major new loads.[33] Significant infrastructure upgrades would need to be recovered from all ratepayers, including those who will reap little if any benefit from the new load. If the large load fails to fully materialize, the impact on ratepayers would be even worse as they would be forced to pay the costs that the large load customer would have otherwise been responsible for.

For the reasons laid out in the Data centers section, while it remains difficult to determine just how much load will actually materialize, it is almost certainly overestimated currently. For these reasons, these large loads are referred to by some as "phantom loads." Most utilities have an incentive to attract new load and build new generation to serve those loads because the existing cost-of-service model allows utilities to earn a rate of return on new infrastructure investments. When these loads fail to materialize, ratepayers may be stuck paying for stranded generation assets that they do not need, raising utility bills for customers through no fault of their own.

No-regrets option

Supply-side resources can saddle ratepayers with additional costs (see Cost section). Even if all additional costs are borne by the large load customers themselves, it still consigns the planet to additional GHG emissions if the load is met by fossil resources. The possibility of installing ultimately unnecessary new generation, should the new load not materialize, only exacerbates these problems. In short, supply-side solutions for explosive load growth pose a risk to both ratepayers and the planet.

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[33] Moderate load growth can spread fixed distribution and transmission expenditures over more sales, reducing the per-unit cost and causing a drop in electric bills (Wiser et al. 2025).

In comparison, **demand-side options offer a no-regrets approach that acts as a hedge against uncertain load growth.** Should the new load actually emerge, demand-side solutions provide additional headroom, lightening the load that must be met with generation resources. Should the load not materialize, the utility will have procured a least-cost energy resource that benefits both participating customers and ratepayers as a whole by reducing energy and capacity costs.

Demand-side resources are also reliable. Unlike supply-side resources that are susceptible to downtime (planned and unplanned), extreme weather conditions, and even damage from animals, energy efficiency is "always on."[34] EE programs have been operating successfully for decades, consistently delivering predictable savings across sectors while mitigating issues like fuel price volatility.

Evaluation, measurement, and verification (EM&V) reports exist to confirm that reported savings are accurate and credible. These reports, which are generally produced every 1–3 years, not only verify achieved savings, but also examine issues like free-ridership to determine what percentage of the achieved savings occurred only because of the program's existence. Verification can be made even more reliable if they rely on "measured" savings that compare actual energy use before and after the installation of efficiency measures. Evaluating behavioral measures goes even further by comparing results from program participants and a control group. In short, the energy efficiency community takes multiple steps to ensure that EE delivers what it promised.

Demand-side measures also buy utilities time. As demand-side procurements are installed, utilities will act in a way that gradually and increasingly lowers the demand that must be met with higher-cost and potentially polluting generation resources. This buys time for utilities to evaluate how much new generation will actually be needed while serving as a reliability resource while new loads interconnect.

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[34] See, for example, Winter Storm Uri, which in 2021 caused failures in both energy generation and distribution systems due to freezing conditions, leading to power outages that caused hundreds of billions of dollars in economic losses and at least 210 deaths. The extreme cold led to a surge in demand that could have been mitigated with more demand-side resources.

Policy and program approaches

Current policy responses underutilize EE and DR

Despite their advantages, demand-side measures have yet to be recognized as a significant part of the solution to the explosive load growth challenge. Most efforts to date have focused on building new gas generation, delaying fossil-fuel retirements, supporting emerging nuclear technologies, and, to a lesser extent, creating new electric rates specifically tailored for large loads.

In this chapter, we summarize and provide distinct examples of the variety of approaches being taken to address explosive load growth. We provide a comparison between the solutions currently attracting the most policy attention (i.e., utility-scale supply-side resources) and underutilized solutions with the potential to meet load more quickly, less expensively, and with fewer downsides (e.g., onsite generation, distributed energy resources (DERs), virtual power plants). Supplemental information for this chapter is presented in Appendix D: Additional policy approaches and program examples.

New gas generation

States are increasingly turning to new natural gas generation to meet rising electricity demand driven by data centers, manufacturing, and electrification. Utilities in Arizona, Georgia, Indiana, Louisiana, Nebraska, Nevada, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and Virginia have proposed or secured approval for gas-fired plants. Nationwide, over 100 GW of new gas projects have been announced, with about 80 GW expected by 2030—more than double the capacity added in the past five years. Actual gas plant construction, however, has been impeded by factors like supply chain bottlenecks, soaring construction costs ($2,000–2,500/kW), and labor constraints (Shenk 2025).

Delaying fossil-fuel retirements

Many U.S. utility IRPs are delaying the retirement of fossil-fuel plants—both coal and natural gas—due to rising electricity demand from data centers and other large loads. States such as Indiana, Louisiana, Maryland, Michigan, Nebraska, Nevada, New York, North Carolina, Ohio, Tennessee, Texas, and Virginia have extended plant operations.[35] California and Illinois have explicitly cited reliability concerns. Federal mandates have also required some retiring plants to remain operational, bypassing traditional regulatory processes. These actions carry significant cost and emissions impacts, with nationwide ratepayer costs projected at $3.1–5.9 billion annually by 2028, and states like California, Texas, and Michigan facing the highest expenses.[36] Without stronger emphasis on energy efficiency and demand-side management, these extensions will further increase costs and undermine decarbonization efforts.

Diesel generators

U.S. Secretary of Energy Chris Wright has vocalized the intent to deploy up to 35 GW of large industrial diesel generator capacity to help meet data center load and curb rising electricity costs (Natter and Saul 2025). However, these generators—which often provide backup power to large C&I customers—are not intended to operate for long durations and are generally not permitted to operate continuously. They are among the most polluting energy sources, and their extended operation can contribute to significant harmful public health impacts. Their operation cost is also considerably higher than that of utility-scale generation, which risks increasing energy costs for all customers (101 Generator 2025; Fakhri et al. 2025; Sidley Austin LLP 2026; UCS 2024).

Onsite nuclear

States are increasingly pursuing new nuclear technologies—particularly small modular reactors (SMRs)—and reactivating old nuclear plants (e.g., Three Mile Island, Palisades Nuclear Plant) as carbon-free solutions to meet growing capacity needs. Georgia, Louisiana, Michigan, North Carolina, Tennessee, Texas, and Virginia are advancing nuclear options through utility plans, legislation, and partnerships. Indiana Michigan Power is planning 600 MW of SMR capacity by 2037 while Arizona utilities are jointly exploring nuclear generation (APS 2025; Indiana Michigan Power 2025). While some private-sector players, such as hyperscalers, have signed nuclear power purchase agreements (PPAs)[37]—including Meta's 20-year deal for 1.1 GW from Illinois' Clinton Clean Energy Center[38]—large-scale new nuclear builds remain costly and complex. **SMRs are unlikely to be commercially deployed in the United States before 2030.** Current nuclear PPAs and reactivation projects are exceptions rather than indicators of a widespread trend toward new nuclear development (Constellation Energy Corporation 2025).

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[35] For example, Georgia Power's 2025 IRP keeps coal plants like Plant Bowen and Plant Scherer operating into the mid-2030s, reversing earlier retirement plans.

[36] The states with the highest potential annual costs include California ($389 million), Texas ($183 million), Colorado ($178 million), Michigan ($171 million), Louisiana ($164 million), and Illinois ($161 million) (Goggin 2025).

[37] A PPA is a long-term contract between an electricity generator (seller) and a buyer (often a utility, corporation, or government) for the sale and purchase of electricity at a pre-agreed price over a fixed term.

[38] The Clinton Clean Energy Center is a nuclear plant that will commence generation in 2027.

Onsite renewables

Several states are exploring or enacting policies to require data centers to use clean energy. **West Virginia's H.B. 2014,** now law, creates a Certified Microgrid Program allowing large energy users to build onsite renewable systems with minimal regulatory oversight, promoting self-sufficiency and resilience (West Virginia Office of the Governor 2025). **New Jersey's S.B. 4143** would mandate data centers operate entirely on renewable or nuclear power once similar standards are adopted across the PJM region, with detailed energy plans required (Smith and McKeon 2025). **Minnesota's failed H.F. 2928** proposed a phased renewable mandate for data centers—65% by 2030 and 100% thereafter—tracked hourly to align real-time usage with clean generation (Minnesota House of Representatives 2025). **Virginia's H.B. 2578,** also unsuccessful, sought to link data center tax incentives to renewable sourcing, efficiency upgrades, stricter generator emissions limits, and waste heat reuse studies (Sullivan 2025). Google has begun launching partnerships to procure its own clean energy capacity to power data centers, an approach being referred to as "bring your own new clean energy" (or BYONCE) (Jacobs 2024; Segal 2024). Together, these measures reflect growing state and corporate interest in aligning data center growth with clean energy and sustainability goals.

Electric rates

Utilities and regulators are increasingly using specialized rate structures and cost allocation mechanisms to address the challenges posed by large new electricity loads, such as those from data centers. The primary strategy is to ensure that these large customers are accountable for the full costs associated with their connection to the grid, including infrastructure upgrades, transmission, and distribution. This approach is designed to prevent the financial burden of serving these large loads from being shifted onto other ratepayers.

Key elements of these rate strategies include

- **Cost recovery:** Large customers are required to cover all costs for new infrastructure or grid upgrades needed to serve their load, often through minimum bill requirements or long-term contracts. This ensures that investments made on behalf of these customers are recouped, even if the customer reduces usage or exits early.

- **Reliability and grid support:** Some rates mandate that large users provide onsite backup generation and allow utilities to curtail their load or remotely disconnect them during grid emergencies, enhancing overall grid reliability.

- **Financial safeguards:** Utilities may require financial guarantees, such as collateral or exit fees, to protect against default and ensure that infrastructure investments are not stranded.

- **Ratepayer protection:** The overarching goal is to shield other utility customers from subsidizing the costs associated with large new loads, maintaining fairness in cost allocation.

Quantitative requirements often include minimum usage thresholds (e.g., paying for at least 85% of contracted capacity), long-term service commitments (ranging from 12 to 15 years), ramp-up periods (usually 4–5 years) to reach full service levels, and full cost recovery for grid upgrades. These measures collectively ensure that the financial and operational impacts of rapid load growth are managed responsibly and equitably while maintaining grid reliability.

Energy efficiency

Over the last couple years, a handful of states have proposed or succeeded in issuing policy actions to utilize energy efficiency and load flexibility to address load growth, primarily from data centers. While these proposals are nascent and many did not pass their state legislatures, they provide models for action. In this section we summarize key features of those actions. Detailed descriptions of these policies are provided in Appendix D: Additional policy approaches and program examples.

Many policy proposals require large new electricity users—such as data centers—to **participate in EE, DR, workforce, or community development programs or to fund such initiatives as a condition of their grid connection or to gain access to other benefits.** These policies are designed to ensure that the costs and benefits of managing load growth are not unfairly shifted to other ratepayers. Mechanisms include minimum bill requirements, mandatory contributions to efficiency funds, and direct cost recovery for grid upgrades. Other policies would add EE requirements to data centers as a precondition for receiving certain tax benefits (e.g., Texas S.B. 2888, Colorado S.B. 25-280, Minnesota H.F. 16, Virginia H.B. 116).

PJM and SPP have proposed rules that would **allow new large loads to interconnect faster if they agree to curtail their load when the grid is constrained.** These loads would avoid capacity market charges while still contributing to transmission planning and costs. They could also reduce their risk of curtailment by deploying contracted or co-located generation or storage.

In addition, some policies **set explicit quantitative targets for energy savings or demand reduction,** often expressed as a percentage of annual load (e.g., 1–2% per year) or as a specific megawatt contribution during peak events. Regular reporting and verification are typically required to ensure compliance and to measure program effectiveness (e.g., California Title 24, Washington Executive Order 25-05, New York S.B. 6394).

Proposals increasingly **encourage or require the aggregation of DERs—such as batteries, flexible loads, and backup generators—into virtual power plants.** These virtual power plants (VPPs) can be dispatched during periods of high demand, providing grid services and reducing the need for new infrastructure. Other proposals introduce new commercial structures, such as bilateral contracting for capacity or "bring your own capacity" frameworks, which allow large users to directly finance and procure EE and DR resources. These approaches aim to accelerate deployment by bypassing traditional utility hesitancy and leveraging the financial strength of large customers. Policies may specify technical requirements for participation, reporting obligations, and remote dispatch capabilities (e.g., Virginia H.B. 2346/S.B. 1100, Colorado S.B. 24-218).

Technology priorities and program models

Demand-side management and flexibility currently contribute only modestly to meeting peak electricity demand in the United States. Load flexibility programs supply about 60 GW of capacity, equivalent to about 7% of national peak-coincident demand, with residential and commercial customers accounting for just 30% of that total (Baldwin 2024). This is despite the rapid deployment of advanced metering infrastructure—as of 2022, over 119 million advanced meters, or over 72% of all meters nationwide, have been installed, creating a strong technical foundation for flexible demand solutions (FERC 2024a).

The potential for growth is substantial. About 30 GW of VPP capacity is installed today, but 150–200 GW of new dispatchable DER capacity is projected to be added to the grid by 2030. If just 30–50% of those new resources are enrolled in a VPP program,[39] that would bring total VPP capacity to 80–160 GW. This expansion could meet 10–20% of peak demand and save an estimated $10 billion annually in grid costs (DOE 2025b). RMI projects that 60 GW of VPPs could be deployed by 2030 (Brehm et al. 2023), while Guidehouse Insights expects flexible residential DER capacity to reach 96 GW by 2032 (Budner 2025).

Supporting this estimate, ICF reported in May 2025 that well-designed customer programs and other load management resources could reduce nationwide peak electricity demand by 10% by 2030, offering significant value, as the final increments of peak demand are often the most costly to serve (Batra et al. 2025).

Table 5 highlights several major categories of demand-side energy management, focusing on both the end uses and enabling technologies across residential, commercial, and industrial applications. The analysis covers climate control, energy storage, electric vehicle integration, water heating, demand response for large customers, and voluntary conservation programs that encourage energy use reductions, illustrating the broad range of solutions now available to optimize energy use in the face of explosive load growth.

Table 5. Load growth drivers, technologies, and program types that can support demand flexibility

Load growth driver	Technology examples	Program types
Building electrification	High-efficiency heat pumps, weatherization, smart thermostats, advanced HVAC controls, smart water heaters, battery storage	Smart thermostat rebates, direct load control, time-of-use rates, VPP programs, low-income weatherization, efficient HVAC
Transportation electrification	Grid-interactive chargers, V2G-enabled EVs	Off-peak charging incentives, managed charging, EV charger incentives, VPP programs
Data centers	High-efficiency computing equipment, advanced cooling systems (e.g., liquid cooling), building management systems, onsite renewable generation, distributed battery storage	Automated demand response, VPP aggregation, energy efficiency incentives/ equipment upgrade programs
Industry	Energy information management systems, automated DR platforms, onsite renewable generation, chemical and thermal storage, hybrid heating systems	Automated DR, interruptibility agreements, VPP programs, pay-for-performance DR

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[39] This represents best-in-class VPP enrollment rates. For example, 50% of Xcel Minnesota's eligible residential customers are voluntarily enrolled in air-conditioning load control programs (DOE 2025b).

Program solutions

This chapter contains examples of the most valuable DSM program types for addressing load growth. These programs provide energy savings, peak reduction, GHG mitigation, cost savings, job creation, and more. We encourage programmers and decision makers to select whichever combination of resources is most appropriate for their circumstance. Examples of specific programs implementing the strategies in this chapter are provided in Appendix D: Additional policy approaches and program examples.

HVAC and weatherization

Electrification of space heating and cooling is poised to be a major driver of future peak demand. **DSM programs in this area should prioritize four key strategies: installing more efficient heat pumps, weatherizing buildings, leveraging HVAC-based demand response, and utilizing thermal energy networks (TENs).**

While heat pumps can be a driver of load growth when they replace fossil-based heating, they can also mitigate load growth when they replace electric resistance heating. Many regions of the country—including the Southeast—extensively use baseboard heating, which generates heat by passing an electric current through a resistive element. This approach can, at its theoretical best, convert electricity directly into thermal energy. Heat pumps generate heating and cooling by *moving* heat, a process that can be 2–4 times more efficient. The replacement of resistance heating with more efficient heat pumps is therefore a key strategy for reducing load growth.

Incentivizing the right type of heat pump matters as well. Different heat pumps have different efficiencies in different conditions, and care must be taken to select models that are circumstance appropriate. For example, in regions that experience extreme cold, cold-climate heat pumps are an ideal solution. Research also indicates that switching from lower-efficiency to higher-efficiency heat pumps can be the most important efficiency measure for reducing peak load at high levels of heat pump deployment (Specian et al. 2021).

To help reduce likely increases in customer costs and strain on the grid, **electrification of space heating should be paired with efficiency improvements in the building envelope**—that is, the parts of the building that separate it from the outdoors, including walls and windows. Such improvements, known as weatherization, can slow uncontrolled heat transfer between the indoor and outdoor environments by increasing insulation in walls, attics, and basements; sealing air leaks (Harrington et al. 2022); or installing higher-efficiency windows.

Averaged across the United States, **modest weatherization measures such as air sealing and increasing the quality and thickness of attic insulation can reliably reduce energy usage by 12–18%.** Deeper building retrofits that add insulation to walls, basements, and rim joists, and install higher-efficiency windows could deliver around 33% energy savings. This can also **reduce peak electric load by approximately 7–10%** (Specian 2023).

Envelope improvements allow a building to maintain a comfortable indoor temperature with a less powerful heat pump. Lower capacity units cost less to purchase, reducing up-front costs, which can be particularly valuable for low-income customers. **The average residential customer who weatherizes an electrified home can expect to save an additional $150–1,200 in operational costs per year, with most households saving $500–800 per year.** Efficient envelopes' ability to reduce demand during some of the grid's most carbon-intensive hours of the year also makes them one of the most effective efficiency measures for reducing

GHG emissions, while simultaneously helping to make buildings safer, healthier, and more comfortable (Specian 2023).

The third key thermal space conditioning strategy is HVAC-focused load flexibility programs. These programs typically leverage Internet-connected thermostats to make small, temporary adjustments to heating and cooling setpoints during peak demand periods. By automating these changes and incorporating strategies like precooling or preheating, they reduce strain on the grid while maintaining customer comfort (PGE n.d.). High-quality thermal envelopes can help buildings better manage these events. Importantly, customers retain control and can override adjustments, which helps build trust and participation.

The results show that **even modest thermostat changes can consistently deliver meaningful reductions—often around 1 kW per household—when scaled across thousands of participants** (Cadmus 2021; ENERGY STAR 2025; McCabe 2023). **This aggregated impact can reach tens or even hundreds of megawatts during critical events,** providing utilities with a cost-effective alternative to building new infrastructure. Nationally, smart thermostats within VPPs could unlock nearly 70 GW of flexible load capacity (Renew Home 2024). Financial incentives for enrollment and seasonal participation further encourage adoption, making these programs accessible and appealing to both residential and commercial customers.

Fourth, **states should support the deployment of thermal energy networks by large load customers (e.g., data centers).** TENs are systems that utilize waste heat to provide heating-related services to buildings within a nearby district (often neighborhood-scale). Because this heat would otherwise go to waste, TENs provide an efficient and fossil-free energy source. They also provide an employment opportunity for workers who might otherwise be displaced in a transition away from gas (Partin et al. 2025).

Water heating

Utilities are increasingly turning to residential water heaters as controllable assets to manage load growth and integrate renewable energy. Efficient and flexible water heating is a crucial strategy for addressing load growth, and is the technology with the second-greatest potential to reduce utility system costs as grid conditions evolve (Specian and Bell-Pasht 2023).

The first key strategy is incentivizing the replacement of inefficient electric resistance water heaters with heat pump water heaters. As explained in the section above, heat pump water heaters (HPWHs) are 3–4 times more efficient than resistance models, have lower annual operating costs, and generally have lifespans 2–3 years longer (Langer 2025). HPWHs typically reduce energy consumption by 1,500–2,500 kWh/year, depending on usage and climate (Jones 2024).

HPWHs can also be extremely flexible, an important consideration with respect to reducing peak demand. Tank-based water heaters are essentially thermal batteries, generating hot water throughout the day and storing it until needed. By equipping water heaters with communication technology that allows them to respond to real-time grid signals, utilities can shift heating away from peak periods, usually with no discernible impact to the customer. At scale, water heater flexibility can defer expensive infrastructure investments and deliver strong benefit-cost ratios. Aligning water heating with renewable output reduces carbon emissions and supports clean energy goals. Water heating flexibility programs typically garner high satisfaction and low opt-out rates from program participants, indicating strong potential for widespread adoption.

Storage

Utility thermal and chemical battery programs provide grid flexibility, resilience, and economic efficiency, making them a cornerstone solution for utilities facing rising load growth. Batteries are primarily a demand response resource, one capable of responding extremely quickly to peak demand conditions. By aggregating thousands of distributed batteries into VPPs, utilities can dispatch their stored energy to provide flexible capacity during high-cost or high-demand periods, reducing reliance on fossil-fueled peaker plants. Thermal batteries can preheat a storage medium, then discharge that heat later without having to draw energy from grid during peak periods.[40] Batteries are an ideal technology to pair with distributed generation as part of microgrid projects (Gyuk et al. 2022). They also provide a hedge against the most extreme impacts of load growth—power outages—by delivering an emergency source of power to buildings that have them installed, including community resilience hubs.

Electric vehicles

As EV adoption accelerates, utilities face mounting pressure on distribution infrastructure, with national studies estimating that unchecked load growth could require $7 billion to $47 billion in upgrades by 2045 under high electrification scenarios (Cutter et al. 2021).[41] The deliberate control and optimization of when, where, and how EVs are charged—an approach referred as "managed charging"—offers a powerful solution to offset this growth.

Instead of charging immediately upon plug-in (unmanaged charging), managed charging uses strategies such as scheduling, rebates, incentives, price signals (passive measure), or direct control (active measure) to shift charging to times that minimize grid stress and reduce costs. Either vehicle owners or utilities can take the lead on managed charging. Utility-orchestrated programs will be subject to instructions from vehicle owners (e.g., have EV fully charged by 7 a.m.) and customer override. Advanced approaches like Distribution Integrated Smart Charging Orchestration (DISCO) go further by managing local distribution constraints (WeaveGrid 2025a). Managed charging offers a rare combination of cost effectiveness and proven technological readiness, making it a foundational tool for utilities navigating the financial and operational challenges of a rapidly electrifying grid.

In the current environment of rapid load growth, expensive generation additions, and high transmission upgrade costs, the value proposition for managed charging is particularly compelling. Managed EV charging can shift 60–80% of peak-period demand to off-peak hours (EnergyHub 2025) and reduce the incremental cost of upgrading grid infrastructure needed to support EV integration by up to 62% (Satchwell et al. 2023). On a per-vehicle basis, managed charging has been estimated to deliver over $300 annually in avoided distribution system costs (WeaveGrid 2025b). And because EVs are parked for long periods, shifting when charging occurs can be done without inconveniencing drivers.

The exact savings delivered by managed charging depend on local conditions such as extant demand, available headroom, and distribution constraints. Managed charging can take various forms as illustrated in figure 23, and utilities are encouraged to adopt whichever combination of strategies is most advantageous for their specific circumstances.

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[40] Thermal batteries can also be precooled, allowing heat to be absorbed later without substantial additional cooling load.

[41] The low estimate is based on forecasted needs on the distribution system based on the methodology used in the California Distribution Resource Planning Proceeding keeping most cost assumptions constant over time, while the high estimate is based on a survey of marginal cost approaches commonly used to estimate load growth-related distribution costs in utility rate cases and regulatory proceedings while assuming cost and number of upgrades driven by EV load will increase over time.

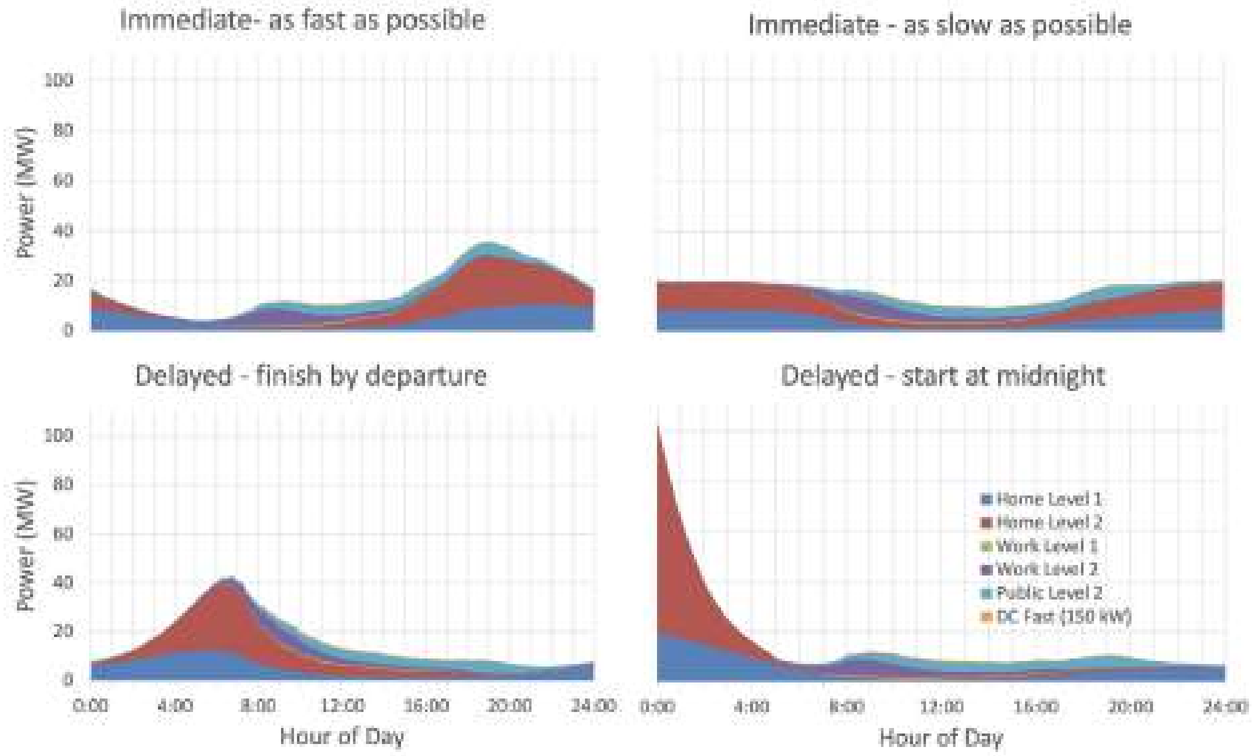

Figure 23. Examples of light-duty EV loads under different managed charging scenarios. Data generated for Baltimore City through DOE's EVI-X tool (DOE 2025a).[42]

Utilities can send price signals to EV customers by offering lower electric rates during off-peak periods. These include time-of-use rates or critical peak pricing, though in the latter case we recommend that utilities provide enough advance notice of these periods so that charging can be shifted accordingly (Alliance for Transportation Electrification 2023; Fitzgerald and Dougherty 2021).

In regions where transportation electrification is expected to be a major driver of load growth over the next decade, it will be valuable to advance capabilities like V2G, perhaps as part of a virtual power plant. Utilities can implement V2G by using existing interconnection processes and guidelines (e.g., for DERs like solar and batteries). They can operationalize V2G using specific rates, though care should be taken to calibrate the frequency of called events to maximize program participation. Utilities can also utilize a V2B (vehicle-to-building) program framework in which EVs supply power to buildings directly to reduce peak demand (Blair et al. 2023; Ghosh 2025).

Examples of programs that help manage peak demand through EVs are provided in table 13, table 14, and table 15.

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[42] Profiles assume 30,000 plug-in vehicles driving 35 miles per day in 50°F temperatures. "Immediate – as fast as possible" assumes vehicles begin charging as soon as possible upon arriving at a charging location and charge at full power/speed until fully charged or the vehicle departs. "Immediate – as slow as possible" assumes vehicles begin charging immediately upon arriving at a charging location, but the charging speed/power is controlled to be as slow/low as possible to spread the charge evenly over the time the vehicle is parked. "Delayed – finish by departure" assumes vehicles wait as long as possible to begin charging so they can still receive a full charge. This strategy uses arrival and departure times from the travel data referenced in the assumptions to shift load during simulations. "Delayed – start at midnight" assumes vehicles begin home charging at midnight because some vehicle owners elect to program their vehicles to start charging at a specific time overnight, which is often midnight.

Large C&I demand response

Large C&I demand response programs use flexible, technology-neutral strategies to incentivize load reduction during peak periods, leveraging automation and behind-the-meter assets. Customers use behind-the-meter assets to reduce load, and can select any technology that fits their operations, provided performance can be verified. These strategies admit a range of solutions such as battery or thermal storage, process curtailment, and efficient HVAC and refrigeration. As industries electrify processes (e.g., switching to electric boilers or heat pumps), their loads can become more flexible and suitable for DR (Johnson et al. 2024).

Programs for large C&I customers typically operate by offering financial incentives for reducing electricity use during peak demand periods. Participation is flexible, as businesses can choose between options with fewer, longer events (e.g., 1–8 events per summer, each about three hours) or more frequent, shorter events (e.g., 30–60 events per summer, each 2–3 hours), with higher incentives for greater commitment. Most businesses participate through third-party curtailment service providers, though direct utility enrollment is also possible. Large load customers can also negotiate bespoke load flexibility arrangements with their utilities. A common arrangement involves payments for providing DR capacity coupled with penalties if the large load customer is unable to provide its promised demand reduction.

These programs have already delivered substantial, independently verified peak demand reductions, economic benefits, and grid reliability improvements. Industrial loads account for nearly half (14.9 GW) of the total potential peak demand savings from U.S. retail DR programs (FERC 2024a). The total flexible DER capacity in the C&I sector reached nearly 78 GW in 2022 and is projected to grow to 268 GW by 2031 (a 14.7% annual growth rate) (Guidehouse Insights 2022).

While proposed legislation is starting to require that data center loads be interruptible during emergency conditions (see House Bill No. 1834 - Data Center Act (2025), for example), **there are limited examples of data centers utilizing DR in their operations** (Nadel 2025). Google has implemented “grid-aware flexible operation,” shifting nonurgent computing tasks to times when cleaner or less expensive energy is available. Google is now expanding this approach to its machine learning workloads, forging new agreements with utilities like Indiana Michigan Power (I&M), Tennessee Valley Authority (TVA), and Duke Energy to curtail power use during grid stress and help utilities plan for future demand (Indiana Economic Development Corp 2024; Terrell 2025).

Portland General Electric (PGE) has partnered with GridCARE to accelerate the connection of data centers in regions with limited transmission capacity. GridCARE is an AI-powered grid flexibility platform that leverages detailed hourly demand modeling and flexible resources to identify pockets of previously invisible grid capacity. In the data center hub of Hillsboro, Oregon, PGE used GridCARE’s flexibility tools to free up more than 80 MW of capacity for new data center interconnections, with over 400 MW expected to be energized by 2029. GridCARE is not currently designed to address multigigawatt data centers (GridCARE 2025, 2026).

Oracle has tested a new software platform, Emerald AI, to flexibly adjust their power consumption in response to grid signals for up to 10 hours.[43] Emerald AI’s software platform successfully demonstrated its ability to curtail AI compute loads 25% for three hours during a grid stress event in a Phoenix data center without compromising the quality of computational outputs (Emerald AI 2025). Emerald AI is also a partner on a flexible 96 MW AI data center that is set to go live in Virginia in 2026 (Harder 2025).

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[43] Other Emerald AI features and services include ramping, rapid and planned response, carbon-aware dispatch, and following utility-provided load shapes (Frank 2025).

In Paris, Data4 is working with Schneider Electric and RTE (France's transmission operator) to use the data center's uninterruptible power supply (UPS) system to ride through voltage and frequency issues, rather than going offline during grid disturbances (Tilton 2025). EPRI is also piloting projects to demonstrate how data centers can provide demand flexibility and grid services (for more details, reference Large C&I load flexibility) (EPRI 2024b).

Although the potential for data center flexibility is clear, hyperscalers have not yet demonstrated a willingness to embrace load flexibility in any way that could potentially compromise their operations. They generally support load curtailment as a voluntary, narrowly defined, and incentive-based option—not a mandatory requirement. Getting data centers on board with load flexibility may require appealing to their desire for speed, predictability, and clarity in the interconnection process (FERC 2025b, 2025a).

Virtual power plants

VPPs are aggregations of demand-side resources like the load flexibility programs described above, as well as batteries and rooftop solar that collectively provide similar services as a generation plant: energy, capacity, and ancillary services. They can defer or avoid T&D costs, help the grid decarbonize, and provide resilience by reducing possible points of failure. Any customer with grid-interactive technologies or the ability to manually respond to grid signals can participate, either through their utility or a third-party aggregator. Their doing so converts otherwise idle behind-the-meter assets into grid resources that can earn participants financial rewards.

As peak demand rises, VPPs can be an extremely valuable behind-the-meter resource for the grid. For example, when a record-breaking heat dome hit the East Coast in June 2025, VPPs were essential in helping the eastern U.S. electric grid withstand surging demand. Grid operators and public officials took emergency measures, but it was the rapid dispatch of hundreds of megawatts of capacity from smart thermostats, customer-sited batteries, and flexible loads that helped prevent widespread outages (FERC 2025d; Martucci 2025). VPPs can be deployed in a matter of months, quicker than any form of utility-scale generation (GoodLeap et al. 2025). DOE projects that VPPs could address 10–20% of peak load by 2030, saving approximately $10 billion per year in the process (Brehm and Tobin 2024).

Recommendations

The playbook for responding to explosive load growth is still being written, and many issues remain to be resolved. This presents a moment of opportunity for good ideas to take root and gain momentum, including that demand-side strategies should be the first-line solution. We encourage stakeholders to be ambitious and specific in their pursuit of DSM solutions, and to rely on key points of agreement (e.g., cost control, reliability) when building support for their positions.

There are roles for legislators, utilities, utility regulators, and large load customers in enabling energy efficiency and load flexibility to play a critical role in managing load growth. In this section, we provide policy and program recommendations these stakeholders should consider as they work to address load growth in their own regions. These recommendations are organized by issue category, but a list of approaches organized by the actors most responsible for their implementation is provided in table 6.

Table 6. Summary of demand-side actions decision-makers can take to address load growth

Decision-maker	Recommended actions
Legislators	• Introduce or strengthen energy efficiency resource standards (EERS) • Set or empower regulators to set and enforce specific utility load flexibility goals • Enable revenue decoupling to eliminate the incentive for utilities to maximize electricity sales • Enable or mandate performance incentive mechanisms (PIMs) that reward utilities for addressing load growth through DSM • Require updated market potential studies (MPS) that evaluate granular time- and location-based DSM opportunities • Eliminate opt-out provisions or require new large load customers to support DSM that benefits their local grid as a condition of their interconnection • Require large load customers to share pertinent energy-related data needed to assess DSM opportunities • Require regulators and utilities to establish VPPs and authorize third-party demand response aggregation

Utility regulators	• Set and enforce utility load flexibility goals • Approve and oversee demand-side PIMs • Require utilities to evaluate and communicate load flexibility options for and to large load customers • Require that updated market potential studies include granular assessments (e.g., feeder level) and consider novel DSM opportunities • Require utilities to adhere to best practices during large load tariff and related proceedings, including a requirement that large load customers engage in an IRP-like process to determine the optimal set of demand- and supply-side resources to meet grid needs (a la all-source procurement) • Require utilities to evaluate VPPs as part of their resource planning processes • Require utilities to share data necessary for third-party aggregators to propose optimized DSM solutions • Analyze and support the potential of thermal energy networks through regulatory proceedings
Utilities	• Provide large load customers with benefits—such as guaranteed access to firm capacity—in return for their commitment to deliver or financially support additional demand-side management resources on the system • Prioritize energy efficiency measures that will reduce peak load in the building sector (e.g., higher-efficiency heat pumps, weatherization) • Launch or expand managed charging and vehicle-to-grid programs to reduce peak load and improve system resilience • Provide technical assistance to data centers prior to interconnection on how to reduce energy consumption and peak demand • Introduce or expand demand flexibility programs, including virtual power plants
Large load customers	• Maximize efficiency and load flexibility capabilities of your facilities prior to interconnection and, if possible, construct thermal energy networks to repurpose waste heat • Actively engage with utilities and other subject matter experts prior to interconnection to determine how to maximize facility's DSM potential • Advocate for capacity accreditation for load reductions achieved as a result of new DSM investments, including those realized through additional financial support of utility programs • Utilize energy attribute certificates (EACs) (i.e., demand-side renewable energy credits) to procure demand-side resources on the private market

Large load customers often have options regarding where to build their facilities. Legislators wary of imposing requirements that might scare away potential investment can instead modify these recommendations as incentives. For example, regulators may be authorized to approve an accelerated interconnection process or lower minimum demand charges in exchange for a minimum standard of demand-side resource adoption or a willingness to opt-in to interruptible service. Legislators can also make the availability of tax breaks contingent on meeting specified efficiency performance thresholds or implementing other DSM strategies.

Expand energy efficiency programs

Even after strong energy efficiency program performance over the past two decades, this report documents that a tremendous amount of energy efficiency potential remains. Appropriate policies and programs will need to be in place to help realize it. A comprehensive list of such programs is found in Appendix C: Cost of energy efficiency and load flexibility. Here we summarize a few high-leverage opportunities.

First, state legislators should **introduce or strengthen their state's energy efficiency resource standards (EERS).** An EERS is a legal requirement for utilities to achieve a certain energy reduction from energy efficiency each year. They are conventionally constructed to create an energy reduction equal to a percentage of retail sales (often on the order of 0.25–3% per year), though a "next-generation" EERS can adopt different benchmarks. EERS have historically been very effective. About 82% of utility energy efficiency program savings come from the 26 states (plus the District of Columbia) that have an EERS in place (Mah et al. 2025).

Second, state legislators and regulators can incentivize utility program efficiency investment by **establishing decoupling mechanisms.** Decoupling disassociates a utility's retail sales of electricity from its profits, removing the disincentive for demand-side measures. Regulators should also approve performance incentive mechanisms (PIMs) that allow utilities to earn performance incentives for meeting additional energy efficiency-related goals. In combination, lost revenue recovery and PIMs remove the disincentive and provide an active incentive to save energy.

Third, **efficiency programs should target energy savings that occur during peak demand periods,** perhaps through an integrated demand-side management framework that simultaneously considers both EE and load flexibility. Managing load growth is in large part an effort to limit the need for additional grid capacity by reducing peak. Given that some of the primary drivers of peak demand are residential heating and cooling, utilities should focus their efficiency programs on reducing loads associated with thermal space conditioning. This includes upgrading heating and cooling equipment to more efficient electric heat pumps, especially in cases where heating load is being met by electric resistance heating. This can also include smart (Wi-Fi-enabled) thermostats that on average reduce heating and cooling energy use by about 8% and also allow load flexibility, reducing summer and winter peak loads by nearly 1 kW per thermostat (Blasnik et al. 2025; Renew Home 2024).

To minimize the strain on peak demand, HVAC improvements should be coupled with envelope upgrades with long effective useful lifetimes like improved insulation in ceilings, walls, and rim joists. It also includes air sealing and reducing any leaks in air distribution systems. These weatherization measures are particularly important for helping low-income customers cost effectively manage the space heating electrification transition.

Electric heat pump water heaters are another energy efficiency solution that can help save energy and keep demand low. Because water heating load tends to coincide with winter peak periods, this measure is particularly helpful in reducing winter energy and capacity needs.

Fourth, **decision-makers should support thermal energy networks as a technically viable and cost-effective efficiency technology for repurposing waste heat from large buildings and facilities.** TENs offer the opportunity for a community-driven approach to energy, but one that requires proper policy support. Building energy codes currently do not offer much support for TENs, and questions about how TENs can help satisfy energy codes lack standard answers.

Local policy or ordinances may be a faster and more effective way to enable TENs. Some policy frameworks are well suited to support TENs such as clean heat standards, “future of gas” proceedings, methane pollution protections, efficiency program GHG goals, and obligation to serve reform.

Policy and regulatory barriers that preferentially benefit investor-owned utilities and restrict outside development will need to be overcome. The same applies to outdated rate structures that do not complement the TEN model. Regulatory frameworks should be updated or clarified to enable local ownership and operation of TENs. Focused thermal energy planning and waste heat mapping can clarify the opportunity.

We also recommend that TENs be developed through meaningful collaboration with large load customers, utilities, policymakers, and environmental justice advocates. Like other demand-side measures, TENs have the potential to provide significant community benefits (including local job creation) and coordination can help maximize those benefits for those who could benefit most from them. For example, installation of TENs can be paired with other efficiency upgrades in disadvantaged communities.

We recommend *Thermal Energy Networks in the United States* (Partin et al. 2025) and *Data Center Heat Reuse: The Opportunity for States* (Gardiner et al. 2025) for more detailed technology and policy recommendations for advancing TENs.

Fifth, **utilities can use artificial intelligence to deliver demand-side solutions more effectively than ever before.** AI excels at identifying patterns in complex datasets. This capability can connect customers with the right DSM programs based on factors like energy usage and housing type. This helps ensure customers can be connected to the most appropriate programs with the right incentives to meet their needs. Utilities can also inform customers about other tax breaks and incentives to enable programs to scale more effectively.

Enable data center efficiency

First, prior to interconnection approvals **utilities should offer technical assistance to data centers on how to lower their energy use and reduce peak demand.** Utilities should focus on solutions that lead to permanent reductions in energy consumption and peak demand that would not materialize otherwise. The permanent reduction in load could come from the data center itself or be realized by other buildings. Certain efficiency solutions, such as repurposing waste heat to support nearby facilities, are difficult to retrofit and should be integrated into the design process.

Direct incentives for energy efficiency in data centers run the risk of free ridership or lead to savings that will eventually be offset by additional compute load. The latter is of particular concern in AI-focused data centers, which often run at maximum capacity (National Academies of Sciences, Engineering, and Medicine 2025). In that case, the efficiency incentives would help the data center become more efficient in terms of useful output per unit energy input, but they would not help the grid or reduce the size of additional power generation requirements. As such, it would effectively constitute a subsidy from ratepayers to data centers.

One of the best resources for information, tools, technologies, and analysis to enhance energy performance in data centers themselves is Lawrence Berkeley National Lab's Center of Expertise for Energy Efficiency in Data Centers (LBL 2025). To better understand data center efficiency from a technical perspective we recommend *Best Practices Guide for Energy-Efficient Data Center Design*, written by researchers from the National Renewable Energy Laboratory (Van Geet and Sickinger 2024).

Second, **legislators should require data centers to pay into utility energy efficiency programs.** Opt-outs are often allowed for high-demand customers, including industrial, even though including them would open up more funds for energy efficiency programs. The common justification for opt-outs is that large load customers already engage in energy efficiency on their own and therefore have no use for utility EE programs.

As it relates to DSM, data centers are a unique class that warrants differentiated treatment. In the absence of DSM, they can single-handedly necessitate expensive grid upgrades that either they or other ratepayers would have to pay for. While utility support of efficiency within data centers themselves may not benefit the grid, data centers' support of efficiency elsewhere in the utility territory would. These large load customers reap benefits from a more efficient and lower-cost power system, just like nonparticipating residential and commercial customers do. If the latter group is paying into EE programs, then nonparticipating large load customers should do so as well. This recommendation is likely to meet resistance from powerful entrenched industries, so getting ample stakeholder buy-in will likely be a requirement.

Third, if overcoming opt-outs is not feasible, **legislators should require that large data centers financially contribute to energy efficiency in another way.** We recommend a process by which data centers pay into existing utility energy efficiency programs in exchange for the achieved savings being counted toward meeting their resource needs. Utility involvement is key here, because while data centers will often procure their own generation, they are not as well positioned to procure EE outside their facilities at scale. Utilities, however, have the necessary processes in place given their years of experience running energy efficiency programs. This includes identifying cost-effective measures, working with implementers, supporting workforce initiatives, and engaging with customers through established relationships.

By working in concert, utilities' existing EE programs can be a conduit for data centers to meet their resource needs. Proceeds can be used to limit the data center's impact on the grid by, for example, supporting efficiency upgrades in parts of the distribution system that would be stressed by the data center's presence. Such an approach would also help expand energy efficiency programs without placing additional pressure on ratepayers. To ensure these energy savings are additional, they should either not be counted toward their state's energy efficiency resource standard, or the EERS should be increased by an amount equal to the load center's contribution.

We also support load ramping provisions in which a large load customer is permitted to increase their demand from zero to full contracted capacity after interconnection. These provisions protect grid reliability by preventing sudden increases in load. We recommend that load ramping provisions be coupled to the procurement of DSM. Each unit of energy or demand reduction paid for by the large load customer should count toward accelerating the ramp rate, providing a pathway to interconnect large loads without having to wait for full supply-side solutions.

Another way that data centers can support efficiency is by paying into a dedicated EE fund. Minnesota provides an example of this approach, albeit without the resource planning component and at a lower scale than is ideal. In June 2025, the state passed H.F. 16/S.F. 19, which introduces a fee structure that data centers must pay into every year to support low-income weatherization and energy conservation programs. The annual payment scales with each data center's peak demand forecast. The legislation also requires utilities to submit a plan explaining how they will be able to serve data center load while still complying with the state's decarbonization goals. If such a fund were to be established elsewhere, we recommend that advocates and decision makers look to their own state goals and specific DSM challenges to determine what gaps they need data center funds to target.

Legislative Case Study: Minnesota H.F. 16

A request from the Chair of Minnesota's House Energy Committee to identify best practices for data center standards ultimately led to the state's passage of H.F. 16, which establishes an annual fund ($2–5 million per year) paid into by large data centers based on their peak demand forecast. The fund is designed to support weatherization and energy efficiency projects, especially for communities reliant on delivered fuels that lack other EE funding sources. Water usage, consumer protections, and economic development incentives were also incorporated into the final bill.

The request led to stakeholder meetings that attracted the interest of many parties including the Data Center Coalition, Meta, Google, Amazon, utilities, and other clean energy partners. This was not a party-line issue; Republicans and Democrats supported different pieces of the legislation. Notably, the legislation paired the weatherization fund with an extension of the sales tax exemption for data centers. This compromise was necessary to secure broad support. The contribution to the annual fund needed to be large enough to be meaningful, but small enough to encourage data centers to still develop in Minnesota. Lifting the EE opt-out provision would have faced steep opposition from powerful state industrial interests.

Several lessons and observations came out of this process. Other states should recognize that each data center operator has unique priorities, and they should not be treated like a monolith. Local communities can also negotiate their own deals with incoming data centers, but often lack the tools to do so. Each state will have different leverage points (e.g., tax exemptions, political environment), and they need to work with what they have. Working with the right partners is critical, and some believe that the bill would not have passed without having a champion in the state legislature (A. Eilers and C. Duffrin, manager of legislative affairs and president, Center for Energy and Environment, pers. comm., November 17, 2025).

Other states have developed policies that would require data center efficiency, though they have yet to be implemented. California's proposed legislation A.B. 222 would require the California Public Utility Commission (CPUC) to provide recommendations for mitigating data center electricity consumption impacts on the electrical grid, including any recommended energy efficiency and load flexibility measures. Texas Senate Bill 2888 would have provided tax incentives to data centers provided they utilize more efficient cooling systems or ENERGY STAR-certified servers (Texas Senate Bill 2888 2025). Virginia's H.B. 2578 unsuccessfully tried to require data center operators to demonstrate sufficient investment in energy efficiency measures to provide system-wide benefits in order to be eligible for sales and use tax exemptions (H.B.2578 2025).

Expand load flexibility programs

Only 6.0% of U.S. energy consumers participated in a retail DR program in 2024, indicating ample room to expand the demand flexibility resource. Doing so requires having appropriate DR programs in place and increasing customer participation in them. There are several program varieties that have considerable potential:

- **Thermal space conditioning:** Programs that curtail heating or cooling loads continuously or intermittently during peak periods. These programs will often lead to a change in the building temperature, which customers can calibrate to suit their comfort level and desire for utility flexibility payments. The comfort impact of thermal space conditioning DR can be mitigated with improvements to the building envelope.
- **Water heating DR:** Grid-interactive water heaters can shift load from peak periods to off-peak periods. Water heaters are effectively a form of thermal storage, meaning customers can still take advantage of hot water even when hot-water charging has been temporarily curtailed. Most water heating DR can be executed with minimal, if any, customer discomfort.
- **EV managed charging:** Many EVs need to recharge overnight before deployment the following day. Yet most customers are unconcerned with when within their vehicle's inactive window that charging actually takes place. Rather than charging EVs during peak periods (e.g., on hot summer afternoons), charging can be deferred to late at night or spread throughout the day so as to not exacerbate peak (see figure 23).
- **V2G:** Having even a modest percentage of EV owners participate in grid stress events as part of V2G programs can save the grid billions of dollars per year. Allowing EV batteries to discharge to the grid during peak periods can yield tremendous benefits for the distribution system, which is the current primary driver of increasing electricity rates.
- **Battery storage:** Customers that have their own battery storage systems (e.g., Powerwalls) can be enrolled in programs to discharge a percentage of their stored energy to the grid during peak events. This allows distribution circuits to serve much higher loads, avoiding the need for bigger substations, distribution feeders, and line transformers. Maximum discharge limits can be established to enable customers to retain charge in the event of a power outage.
- **Industrial flexibility:** Industrial DR programs are amongst the most mature DR programs. The industrial sector is quite varied with loads having a wide range of interruptibility. As such, utilities often negotiate bespoke agreements with industrial loads regarding what loads they can shed or shift in exchange for compensation. These programs should be continued and expanded.
- **Data center flexibility:** Data centers have historically been reluctant to participate in DR programs, despite the significant potential power system benefits for doing so. However, if those data centers have uninterruptable power supplies and back-up generation onsite, they are candidates to shift from grid electricity to back-up power for a limited period of time. Up to 40% of data centers' computing needs are not time sensitive, which makes them attractive candidates for load shifting (Gaster 2025). Even in the absence of back-up power, data centers may be able to shift loads in time (e.g., delaying AI model training) or in space (e.g., rerouting computing tasks to a different data center in a region not experiencing grid stress) (Vincent 2023). Google, Oracle, and Schneider Electric have provided models for how to do so.

> Hyperscalers have communicated their support for load curtailment as a voluntary, narrowly defined, and incentive-based option—not a mandatory requirement. If data center flexibility is not required by law, traditional DR incentives alone will likely be insufficient to motivate participation. In these cases, valuable alternative benefits such as faster grid interconnection, lower minimum demand charges, reduced requirements for firm service, and ready access to power should be used instead.

Legislators have the ability to set specific load flexibility goals or empower utility commissions to set them. Either way, DR targets are an excellent option to ensure the demand flexibility resource is being utilized. These goals can take forms like annual reductions in MW, demand reductions during specific hours, number of customers enrolled in DR programs, number of grid-interactive building technologies (e.g., smart thermostats, connected water heaters) installed, and minimum load flexibility requirements for new construction.

Utility regulators should direct utilities to examine all potential demand flexibility solutions and procure all cost-effective DR resources. Part of this requirement must involve direct and focused conversations between the utilities and the large load customer on pathways to reduce their loads on high-demand days. Absent these requirements, the only point of contact large load customers may have with utilities are with their economic development or sales teams, neither of which is guaranteed (or is necessarily capable) to talk through and examine all the flexibility options the large load customer could avail itself of. These large loads are so large and have such a large impact on the grid that leaving these conversations or program uptake to chance is insufficient, especially since data centers have yet to demonstrate a significant willingness to engage demand flexibility for the grid's benefit on their own. These engagements provide valuable opportunities to talk through utility DER programs as well.

Steps should also be taken to evolve traditional demand-side management programs within regulatory, market, and planning frameworks to include both EE and load flexibility, an approach referred to as integrated demand-side management (IDSM). For example, smart thermostats can provide both energy savings and load flexibility, but many states and utilities have separate targets, budgets, and cost-effectiveness tests for EE and DR, making it difficult to optimize or fully value efficient building technologies capable of load flexibility. Regulators should update policies that allow and encourage utilities to pursue IDSM goals. They should also require utilities to develop programs that incentivize both EE and DR while ensuring that EM&V methods quantify and reward the full value of these combined resources.

Update and improve market potential studies

Load growth is a function of geography, with some areas experiencing significantly higher growth than others. Utilities will need to determine where and to what extent these loads are going or likely to materialize on their system, then ensure that feeders, substations, and other infrastructure are capable of meeting that need.

Many utilities rely on market potential studies (MPSs) to determine the amount of energy efficiency that is technically, economically, and realistically achievable. These studies often feed into the IRP process and are important components of procuring cost-effective demand-side measures (see Kramer and Reed (2012), for example). However, many of these studies have common and significant design flaws that hamstring demand-side solutions (e.g., inadequately evaluating DR potential, excluding savings opportunities, underestimating achievable potential).

Because MPSs often feed into the IRP process, they are important components of realizing cost-effective demand-side measures. We recommend that legislators and regulators require these studies to consider all demand-side options, including those that are new or that have not customarily been examined. These include opportunities to reduce peak demand in data centers, execute managed charging for electric vehicles (EVs), and help industrial electrification be more efficient.

These studies should also examine the potential of virtual power plants. The complexity of coordinating hundreds or thousands of distributed energy resources for the benefit of the grid without adversely impacting customers poses a technical challenge. However, successful VPPs have been established (e.g., California's Demand Side Grid Support (DSGS) Program) and advances in grid-interactive building technologies and the technology needed to orchestrate them have matured (CEC 2025a). Pilot programs can be used to refine the approach in advance of scaling.

In addition, MPSs should be required to examine energy efficiency and load flexibility potentials at a granular level wherever possible. This includes locations on the distribution system that are expected to experience outsized load growth, perhaps due to the proximity of a data center, EV charging depot, or a neighborhood with ample space heating electrification. They should also examine DSM potential with improved time granularity, to understand when efficiency and flexibility measures are able to deliver the most value.[44] These assessments would constitute a change from the ways in which MPSs have traditionally been developed. To keep the analysis timely, decisions will have to be made about the minimum amount of information required to properly assess DSM's full potential.

Finally, utilities should be required to direct investments toward all achievable cost-effective demand-side potential identified in these improved MPSs. Particular attention should be paid toward locations on the distribution system where DSM can avoid expensive infrastructure upgrades.

Require integrated resource planning that optimizes for DSM

Not all utilities engage in integrated resource planning, but the principles of identifying electrical system needs, then evaluating a range of supply- and demand-side options together to determine what set of resources can best meet the needs of the system affordably, reliably, and safely should be followed for all new large loads.

When utilities are required to examine solutions in a holistic way, new optimal combinations of generation, electrification, distribution capacity, and so on can reveal themselves. The alternative is siloed potential studies that are unable to account for interactive effects between energy resources. Moreover, when utilities are required to evaluate a bevy of options, it provides more levers that regulators can pull to compel an optimized solution.

If the analysis has not been done as part of a formal IRP process, regulators should require utilities to engage in something akin to a mini-integrated resource plan process when new large loads—such as data centers—seek interconnection. These mini-IRPs should be consistent with the principles of all-source procurement in which all available energy resources (both supply and demand side) are considered and compared in a technology-agnostic way.

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[44] For example, Hawaii uses load growth scenarios to determine whether the demand forecast for a transformer or circuit exceeds the equipment rating. If so, a more granular analysis of hourly grid need is conducted (Schwartz et al. 2024)

This sort of analysis is necessary because even in cases where data centers procure their own generation, they are not typically positioned to understand where energy efficiency or load flexibility would be most useful to relieve grid stress. There may also be limited opportunity to procure DSM on their own.[45] The requirement for data centers to integrate DSM into the procurement process, coupled with utility participation, provides a pathway to connect data centers' resource needs with existing utility DSM programs that might not occur otherwise.

Utilities, however, have the necessary processes in place given their years of experience running energy efficiency programs. This includes identifying cost-effective measures, working with implementers, supporting workforce initiatives, and engaging with customers through established relationships.

Integrated planning is especially important in the distribution system, where the majority of load growth-related costs are expected to occur. Example planning processes exist in states like California and Colorado, which require grid needs assessments (GNAs) to consider the potential of EE, DR, and DERs to address identified needs. Colorado's GNA process specifically calls for geographically targeted deployment of DSM to defer upgrades. Hawaii's Integrated Grid Planning (IGP) process harmonizes distribution, transmission, and generation planning through iterative modeling and shared assumptions, allowing the Hawaiian Electric Companies to identify solutions for transformers or circuits that require mitigation, including through NWAs (Schwartz et al. 2024).

This recommendation is in line with flexible interconnection programs, which refers to a set of strategies, technologies, and regulatory frameworks in distribution system planning that allow new loads to connect to the grid in ways that reduce stress on the system. This approach may also help large loads connect to the grid more quickly, as flexible loads that can shift or curtail demand place less burden on the system and may avoid the need for expensive upgrades like new transformers or reconductoring transmission lines.

Regulators should require these resource plans to be filed with adequate advanced notice to determine whether fair competition between supply- and demand-side options has been done. Often, utilities will claim that new large loads need to be accommodated on an expedited schedule, creating emergency-like conditions in which regulators default to approving conventional load growth solutions, like gas plants, without adequately allowing them to compete against other resources.

Within utility programs themselves, DSM is both highly popular and underutilized. An ICF survey of 100 utility program leaders found that 98% of respondents say that evolving energy efficiency programs is critical to realizing a return on investment.[46] Sixty-three percent said they use demand-side strategies to address capacity issues all or most of the time, but 68% said that increasing electrification while meeting energy reduction goals was a moderate or significant challenge (ICF 2025).

These results suggest that regulators may encounter tailwinds when requiring DSM be more robustly incorporated into integrated planning processes. Actions like requiring new load management strategies be aligned with optimizing T&D investments, and integrated planning that includes placing EE and DR on an equal footing as other resources, represent a big change from how traditional EE programs are designed and managed today.

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[45] One exception are demand-side environmental attribute certificates (EACs), which offer a pathway for data centers to finance and earn credit for energy, demand, and GHG savings achieved in buildings they do not own. EACs, which operate similarly to supply-side renewable energy certificates (RECs), are a nascent tool, but one with promise. For more, see ACEEE report *Leveling Up Decarbonization* (Specian 2025).

[46] Utility program leaders are those with a minimum seniority of director.

Support VPPs and NWAs

VPPs provide critical grid services by reducing the energy and capacity the rest of the grid needs to provide. To keep program costs low, successful VPP programs use technologies like smart inverters and onboard telemetry to conduct device-level measurement instead of installing additional metering infrastructure. While VPPs can accommodate location-specific dispatch, that sort of targeting is uncommon and should be expanded. VPPs should also fairly compensate customers for the services they provide and prioritize deployment to the hours of greatest grid need. Working transparently with third-party aggregators can help realize VPP benefits quickly and at scale.[47]

C&I participation in VPPs remains an area for growth, with most current capacity coming from manual DR programs (Wood Mackenzie 2024). Even still, only 4–10% of potential C&I DR capacity is currently enrolled in in wholesale programs (ESIG 2025). Technology improvements and better program design can boost C&I enrollment, unlocking multigigawatt potential. Utilities or aggregators that own or operate customer-sited resources should expand their offerings to include technologies like lighting, smart thermostats, water heating, refrigeration, EV chargers, and batteries.

Utilities should also consider implementing customer-friendly VPP features such as locking in compensation rates for multiple years, avoiding penalizing participants for nonparticipation, and ensuring customers with batteries retain enough charge for their own resilience needs. Utilities should enable easy data access for customers and third-party aggregators in a way that facilitates easy collaboration. Utilities concerned about whether VPPs will deliver when needed can consider penalties for aggregator underperformance (to ensure costs are not transferred to ratepayers) or utility ownership of customer-sited resources, which may give them more reliable and predictable capacity.

State planners can follow the models of Michigan Energy Savers Club and Minnesota's Sartell/Sauk Rapids pilots, which successfully tested the ability of targeted DSM to defer distribution upgrades. Oregon requires at least two NWA pilots in distribution system plans, developed with community input (Schwartz et al. 2024).

Disclose energy data

Legislators and regulators should require large load customers to share pertinent energy-related data necessary to evaluate options for responsible load management. Pieces of critical information include anticipated energy demand, load shape, and flexibility potential. Data center owners and developers are often reluctant to share that information, and utilities, to date, have generally not demonstrated an interest in providing that information in a way that could clarify the potential for demand-side solutions.[48]

Developing national or multistate standards, protocols, and platforms for the collection of these data will help reduce compliance costs and improve accountability. When data centers report their GHG emissions, they should share their methodology to ensure their emissions can be consistently counted alongside other economy-wide carbon accountings.

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[47] For example, service providers like Voltus, CPower, EnergyHub, and Renew Home manage gigawatts of flexible loads across a variety of end-use categories.

[48] Allowing these data to be shared under a nondisclosure agreement if there are legitimate security or business concerns associated with their publicization is already common practice and should continue.

New Jersey provides an example of how to do this through S.B. 4293, their 2025 bill concerning water and energy usage at data centers. The law requires the owner or operator of a data center in the state to prepare and submit a water and energy usage report to the Board of Public Utilities that contains information including (An Act Concerning Water and Energy Usage at Data Centers and Supplementing Title 48 of the Revised Statutes 2025):

- the total energy consumption in kilowatt hours, including the use of electricity, fuels, and other energy sources used for cooling
- all onsite power supplies
- the total energy consumption of information technology equipment; performance calculations and indicators for the data center, including the energy reuse factor, power usage effectiveness, renewable energy factor, and water usage effectiveness
- the average set point information technology equipment intake air temperature
- the average waste heat temperature
- the amount of electricity derived from renewable energy
- the amount of reused waste heat

Data transparency is also critical for enabling third-party aggregators to provide DSM solutions. Requiring informational parity for aggregators provides them the opportunity to fairly compete with utility programs and ensure the lowest-cost options are selected.

Utilities possess incumbent advantages including far greater access to information and a guaranteed return on investment for building new infrastructure. For example, utilities understand when load growth will overwhelm a feeder and require new distribution system investments. Without access to that information, third-party aggregators are deprived of knowledge of a value stream that would enable their offerings to be recognized as more cost effective. This informational asymmetry fundamentally constrains aggregators' business models, leading to fewer companies offering alternative services and depriving ratepayers of lowest-cost solutions. In December 2025, the Colorado Public Utilities Commission supported this principle by ordering Xcel Energy to expand public access to its detailed, node-level capacity maps so that flexible resources can better address load growth (Colorado Public Utilities Commission 2025).

New metrics may be needed to capture data center-enabled efficiency and flexibility realized outside of their campuses. For example, if data centers pay into low-income weatherization programs, those energy, demand, or GHG savings can be subtracted from totals used in existing metrics like Power Usage Effectiveness (PUE), Energy Reuse Effectiveness (ERE), or Carbon Use Effectiveness (CUE) (see Van Geet and Sickinger (2024)). These new metrics would capture data centers' contributions to regional efficiency, providing a way to both gauge their accomplishments and offer recognition for the savings they enable.

Data transparency can also enable holistic lifecycle analyses that quantify data centers' impacts on the economy and the environment. This kind of sustainability assessment can reveal the trade-offs the data center load growth demands, such as delaying retirement of fossil plants. Without these data, it is not possible to develop alternative scenarios to meet load growth in a comprehensive, optimal way.

Conclusion

States and utilities have multiple ways to respond to explosive load growth. This report concludes that demand-side measures—energy efficiency and load flexibility—should be a first-line solution. However, to date, these opportunities have been underutilized as planners scramble for more expensive supply-side options that lead to higher electricity bills. This neither optimizes the power system nor ensures affordability for consumers.

Energy efficiency and demand response provide multiple advantages. They are, respectively, the lowest-cost energy resources for managing electricity consumption and peak demand. At a national level, enough DSM potential exists to offset new data center load growth through 2030, though different regional profiles exist. These resources can be scaled up in a matter of months, while supply-side resources may require years to pass through regulatory review, supply chain lags, procurement, and associated T&D upgrades. Demand-side solutions also help protect ratepayers from cost increases, expensive and polluting technologies, and negative climate impacts.

Large load customers, including data centers and gigafactories, should be required to support DSM as appropriate at a site or system level, either as a precondition for receiving other benefits or as a component of interconnection. C&I customers and their utilities should negotiate bespoke DR agreements or deploy automated DR platforms or work with service providers that can help manage for reliable, affordable electricity provision for all customers.

Building electrification load can be addressed by efficient thermal space conditioning through efficient heat pump installation, building weatherization measures, and the replacement of electric resistance water heaters with heat pump water heaters. Transportation electrification should be addressed through electric rates, managed charging, or vehicle-to-grid programs that shift EV charging loads away from times of peak power demand while guaranteeing EV charging meets consumer requirements. VPPs and aggregator business models can be complementary to utility models and can offer a variety of sectors access to improved demand response services and benefits.

Ultimately, DSM can be a preferred utility solution to rapid load growth. Data centers can take a leadership role in navigating the system-level challenges and opportunities their new facilities create, which includes paying in to the upgrades that will enable these loads to have reliable power supply without harming other customers. Public policy including data provision, state legislation, and utility planning is essential to ensure that the variety of costs, benefits, investments, and upgrades are enabled as the power system grows.

Energy efficiency and demand response are a strong and no-regrets foundation upon which additional investments can be evaluated. Explosive load growth offers an opportunity for improvements in energy productivity and efficient technology deployment across the economy.

Appendix A. Load growth forecasts

This appendix contains additional information and data used to generate the summary conclusions of the load growth challenge chapter.

Load growth drivers

Data center electricity demand is set to surge across the United States and globally through 2030, with growth driven primarily by hyperscale cloud and AI-ready facilities. According to utility submissions to the Federal Energy Regulatory Commission (FERC), six regions of the country are expected to account for 80% of projected load growth through 2030 (see figure A1). Hyperscalers like Amazon, Meta, Microsoft, and Google are expected to account for about 60% of industry growth, with their share of global data center demand rising from 35% to 45% by 2028 and U.S. capital expenditure (CapEx) investments exceeding $1.8 trillion. States expected to experience the most data center load growth include Virginia, Georgia, Texas, Pennsylvania, Ohio, North Carolina, South Carolina, and Indiana (Howland 2025; Kunkel 2025; Skidmore 2024a; Wilson et al. 2024). Some utilities are already receiving data center power requests that exceed their current generation capacity (Kearney and Dareen 2025).

Figure A1. Regions driving anticipated load growth through 2030 according to utility estimates. Data compiled and figure created by Wilson et al. (2025).

Many load growth forecasts do not fully incorporate ongoing and future improvements in data center energy efficiency. Advances in server technology (e.g., NVIDIA's Grace CPU Superchip, which combines central processing unit (CPU) and graphics processing unit (GPU) functions to deliver more computing power with less energy use), cooling systems (e.g., liquid cooling, which can reduce facility-wide energy use by about 10%), and training and inference algorithms could significantly reduce the actual electricity needed for new data center capacity, all else being equal (Rebarber 2023).

In specific implementations, such as Google's Project Deschutes, end-to-end energy efficiency improvements of approximately 3% have been achieved alongside significantly higher computing densities, reaching up to 1 MW per rack (Iyengar and Huffman 2025). To encourage widespread adoption of these innovations, Google has shared the design and best practices for Project Deschutes through the Open Compute Project, fostering industry collaboration and standardization. Additionally, the Mt. Diablo project, a collaboration between Google, Meta, and Microsoft, aims to standardize high-voltage (±400 VDC) power delivery for data centers, which reduces energy losses and supports the higher power needs of modern AI hardware. These ongoing innovations in cooling and power distribution underscore how continued efficiency gains can help mitigate the impact of data centers' expansion on electricity demand, suggesting that load growth forecasts that overlook such advancements may overestimate future energy needs.

Data centers

Data centers are the dominant driver of new electricity demand nationwide, with the fastest growth in Northern Virginia (PJM), the Southeast (Georgia, North Carolina, South Carolina), Texas (ERCOT), and parts of MISO and SPP. California, the Southwest, and the Northwest also see substantial increases, though volumes are smaller or more distributed. The current distribution of planned data centers is presented in figure A2. A more granular directory that maps data center locations worldwide is provided by the Data Center Map research tool (Data Center Map 2025).

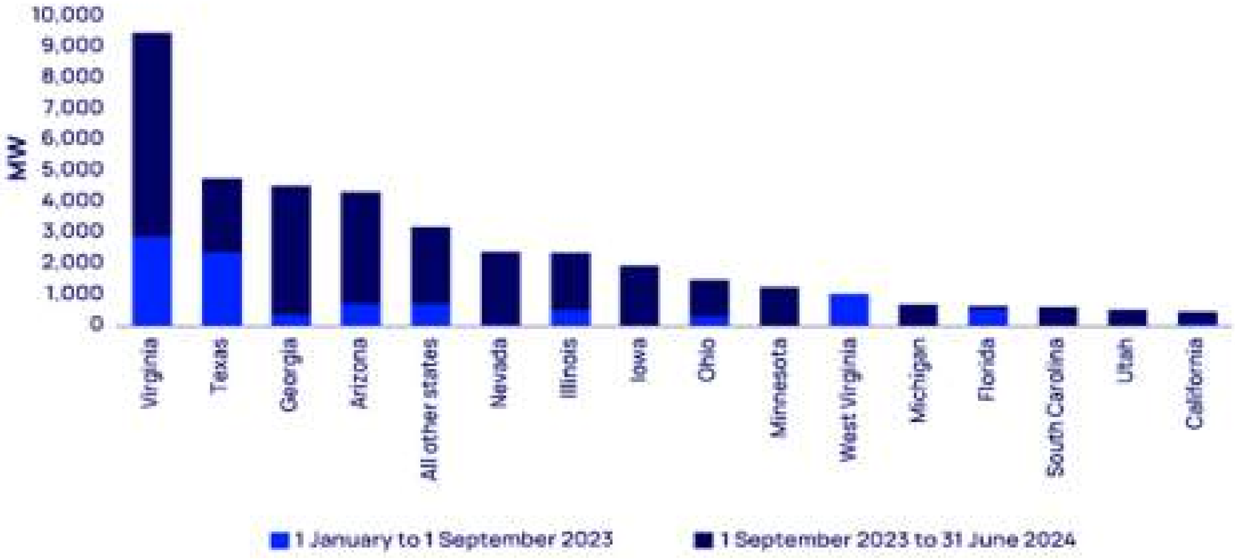

Figure A2. Capacities of data centers announced since 2023. Figure sourced from Seiple (2024).

This concentration of load highlights the critical need for regional planning, flexible generation, and transmission expansion, as data centers' rapid growth can create local reliability pressures even in areas with ample overall capacity. The scale and pace of this demand growth underscore the value of efficiency and flexibility as demand-side strategies, which are both cost effective and readily deployable, particularly given the high costs of supply-side resources.

PJM

PJM, which includes Northern Virginia, the world's leading data center hub, is preparing for significant electricity demand growth over the next 15 years. PJM's latest forecast projects summer peak demand will rise by about 70,000 MW, reaching 220,000, driven primarily by large-scale data center development (PJM 2025b). Specific to Northern Virginia, the Northern Virginia Electric Cooperative (NOVEC) projects that data center peak loads will jump from 1,050 MW in 2024 to nearly 5,900 MW by 2029, driven by over 100 new data centers. NOVEC's projections are based strictly on projects with signed contracts, showing data center loads reaching more than 11,700 MW by 2034 and 12,500 MW by 2039, with a total forecast capacity of approximately 16,500 MW (NOVEC 2025). Dominion Energy, the largest utility serving Virginia, similarly projects rapid growth: demand in its Virginia service territory will grow by 5% to 5.5% annually over the next decade, more than double the historical rate, and could double by 2039. Dominion's latest integrated resource plan (IRP) includes significant new investments in offshore wind, solar, battery storage, and natural gas-fired generation to meet this surge. The utility's IRP shows that total demand in Virginia could rise to 26,623 MW by 2039 (Dominion Energy 2024) and indicates that data center-driven load growth could require delaying the planned retirement of several coal plants and adding up to 3,000 MW of gas-fired generation (Fisher et al. 2024). In 2024, 15 new data centers came online within Dominion Energy's Virginia service territory, adding a total of 977 MW of new capacity. An additional 15 data centers are expected to be added in 2025 (Pilz et al. 2025).

Independent forecasts reinforce these projections. Virginia's Joint Legislative Audit and Review Commission (JLARC) expects unconstrained demand in Virginia is expected to double within 10 years, largely from data centers in Dominion's service territory (JLARC 2024). JLARC's independent forecast closely aligns with PJM's projections. In 2023, Virginia led the nation in data center electricity use, consuming 33.9 million MWh, over a quarter of the state's total. Under high-growth scenarios, data centers' share of electricity use in the state could reach 46% by 2030. Of the 15 states projected to drive 80% of U.S. data center load growth, four—Virginia, Illinois, Pennsylvania, and New Jersey—are in PJM (Kearney and Dareen 2025).

Similar growth is emerging outside Virginia within the PJM region. In Illinois, ComEd projects 34 TWh of data center demand by 2040 and reports 14 GW of projects in its interconnection queue, representing an estimated 105 TWh of potential annual consumption (Zeng and Knight 2025). In New Jersey, PSE&G forecasts data center peak demand will rise from 343 MW in 2024 to nearly 1,200 MW by 2030, and 1,545 MW by 2045 (PSE&G 2024). American Electric Power (AEP), which has significant overlap between its service territory and states under PJM's authority, expects retail load to grow 8.6% annually through 2027, driven by commercial demand from new industrial and data center facilities requiring about 20 GW of new power (AEP 2025).

PJM itself has revised its load forecasts upward, attributing much of the increase to data center development. The 2025 Long-Term Load Forecast projects summer peak load to grow by 3.1% per year over the next decade, with Dominion and Eastern Mid-Atlantic Zones facing the highest growth rates (PJM 2025a). Independent modeling suggests that, by 2040, data centers alone could drive a 20% increase in PJM peak load and a 28% rise in annual energy consumption.

Southeast

The Southeast is seeing rapid electricity demand growth driven by data center expansion, particularly in Georgia, North Carolina, South Carolina, and Tennessee. In Georgia, Atlanta-area data centers are expected to account for the majority of data center growth in the state. According to Georgia Power, 80% of its expected 8,200 MW load increase by 2030 (Dunlap 2025) is tied to new data centers, which are expected to account for 24.6 GW of the total 36.5 GW demand in its service territory (Skidmore 2024b). To meet this growth, the utility is planning continued coal operation, investments in methane gas infrastructure, and increased renewable energy production.

In North Carolina, 83 active data center facilities are concentrated around Charlotte and Raleigh. Duke Energy Carolinas has signed agreements to connect 2 GW of new data centers, driving projected load growth of 4 GW between 2024 and 2030—eight times higher than the 2022 forecast and 2 GW above the 2023 spring estimate. This surge is part of a broader SERC-East trend, with net internal demand expected to rise by nearly 8,000 MW over the next decade, fueled by population growth, industrial projects including data centers, and accelerating electric vehicle (EV) adoption. In South Carolina, Santee Cooper now expects load to reach 6,000 MW by 2027, up from its 2023 forecast, driven by population and industrial growth.

Regional projections underscore the scale: EPRI estimates Georgia data center consumption could rise from 6.2 million MWh in 2023 to 8–16.4 million MWh by 2030 (up to 9.9% of state use). North Carolina could grow from 2.7 to 3.4–7.1 million MWh (up to 4.6%), South Carolina from 2.0 to 2.6–5.4 million MWh (up to 5.8%), and Tennessee from 1.2 to 1.7–3.5 million MWh (Kearney and Dareen 2025). Collectively, these states represent the Southeast's highest concentration of projected data center-driven load growth, highlighting the urgent need for generation, transmission, and reliability planning.

Overall, utilities across the Southeast project new electricity demand by 2035 from industrial growth and data center expansion, including 11 GW from Georgia Power, 7–9 GW from Duke Energy, and up to 12 GW from the Tennessee Valley Authority (TVA). Southern Company (which owns Georgia Power) already has contracts in place with large load customers that will add 7 GW of load by 2029, and it projects new load additions of 50 GW over the next decade. It plans to meet this load with five combined cycle gas units and 11 battery storage facilities (Walton 2025d). Peak demand in the SERC-Southeast region, which includes Georgia, Alabama, and Mississippi, is projected to increase by 17% over the next decade, from 46,984 MW to 55,078 MW by 2034. Meeting this surge will require the Southeast to build and interconnect over 80 GW of new generation by 2035, or about 8 GW per year.

ERCOT

Texas hosts about 336 data centers as of early 2025, with Dallas–Fort Worth as the largest hub. Data centers now account for 8.8% of statewide electricity use, and growth is accelerating. The $500 billion Stargate AI project alone is expected to require 15 GW across multiple sites. ERCOT projects data centers and other large flexible loads will add nearly 60 GW of peak summer demand by 2031, with data centers making up half of that total. Approvals are also surging, with 9.5 GW of large flexible load capacity expected by the end of 2025—a 73% increase over 2024. CenterPoint Energy forecasts more than 10 GW of peak load increase by 2031, almost a 50% increase over current peak demand, with a significant percent coming from data centers (Walton 2025b).

MISO

Data centers are the single largest new source of demand in the MISO region, projected to contribute 23–37 GW of peak load (149–241 TWh of annual consumption) by 2044 (Bennett and Dholakia 2025; Mckendry 2025).

In 2023, data centers accounted for 6% of energy consumption in Illinois, consuming 7 million MWh of electricity. This figure is expected to rise rapidly—even conservative estimates see data center load in Illinois reaching 9.6 million MWh per year in the near future, while high-growth scenarios show as much as 220 million MWh per year by 2045 (Mattioda et al. 2025). Ameren Illinois alone has secured construction agreements for 2.3 GW of new data center capacity, projecting 5.5% compound annual sales growth from 2025–2029 (Lyons 2025). Large quantum computing facilities in Illinois are also expected to be a significant new load in the MISO region, requiring tens to hundreds of megawatts of continuous power, with cooling as the dominant load (Gillespie 2024)

Other states in the region are seeing parallel surges. Indiana utilities report nearly 30 active data center proposals announced by hyperscalers like Amazon, Google, Meta, and Microsoft. Utilities like Northern Indiana Public Service Company (NIPSCO) are projecting between 2,600 and 3,200 MW of new load by 2030, and up to 8,600 MW by 2035 , while Duke Energy Indiana's high forecast adds 500 MW over the next five years, starting in 2027 (Duke Energy 2024). In Iowa, Alliant Energy has already contracted 2.1 GW of peak demand from data centers (Alliant Energy 2025). DTE in Michigan has contracted to serve 1.4 GW of new data center load—a load increase of 25%—with another 3–4 GW in late-stage negotiations. The utility plans to serve this load with a new combined cycle gas plant (Walton 2025c).

By 2030, EPRI projects that data centers could account for 6.5–12.6% of Illinois' total consumption, 13.4–24.2% of Iowa's, 1.5–3% of Minnesota's, and up to 0.5% of Wisconsin's. Iowa and Illinois stand out as clear hubs, while growth in Minnesota and Wisconsin is expected to remain more modest.

California

California is experiencing accelerating interest in data center development. The California Energy Commission projects peak demand from data centers could reach 2 GW by 2030 and 4.5 GW by 2035 under a high-growth scenario, with annual growth rates of 8–11% through 2040 (CEC 2025b; Chen and Harms 2024). Pacific Gas & Electric's (PG&E's) interconnection queue has surged from 4.4 GW in spring 2025 to 12.8 GW, with the utility expecting 3 GW of new capacity online by 2030. That capacity alone would generate roughly 14,000 GWh of new annual demand, rising to more than 20,000 GWh by 2045 as installed capacity reaches 4.5 GW (Conde 2025).

Northwest

In the Northwest, data center electricity use is projected to double by 2046, reaching levels comparable to regional EV load and contributing to system peaks of 47,000–60,000 MW (up from 35,000 MW today) (Northwest Power and Conservation Council 2025). Near-term growth is steep, with utilities and the Northwest Power Conservation Council forecasting 1.5–6.2 GW of new demand from data centers and chip fabrication plants (or “fabs”) by 2029 (Wilson et al. 2024). Bonneville Power Authority alone expects nearly 3 GW of new data center load over the next five years (Bonneville Power Administration 2025), while Portland General Electric projects its industrial load—driven largely by data centers and chip fabs—will nearly double over the next decade (Northwest Power and Conservation Council 2024).

Southwest

Utilities in western states are projecting steep load growth from data centers, with annual energy demand rising 32% by 2030 and 55% by 2035 compared to 2025 (Kapiloff et al. 2025). In Arizona, data centers currently consume 7.4% of statewide electricity, a share expected to rise to 8.8-12.7% by 2030 and potentially as high as 16.5% under a high growth scenario (Kearney and Dareen 2025). If all proposed projects are built, Arizona’s peak demand could triple, requiring up to 29 GW of additional power by 2030 (Arizonans for a Clean Economy 2025). In New Mexico, Public Service Company of New Mexico (PNM) reports that 87% of its 4,197 MW of interconnection requests are from data centers, pushing annual energy demand 11–12% above its 2023 IRP projections by 2030−2035 and raising peak demand by up to 40%. Nevada’s data center capacity, concentrated in Las Vegas and Reno, is projected to surge nearly tenfold, about 953%, reaching 3,812 MW by 2030.

SPP

Data center-driven load growth is a significant factor shaping electricity demand in the SPP region, which will account for 7% of national data center demand. Data center electricity demand in SPP is projected to rise from 17 TWh and 2 GW peak load in 2023 to 62 TWh and 8 GW peak in 2034, and 98 TWh and 12 GW peak by 2050, consistent across baseline, moderate, and full electrification scenarios (Jones et al. 2024). State-level projections indicate substantial variation: Nebraska and North Dakota could see data centers consume 25–31% of statewide electricity under high-growth scenarios, while Oklahoma faces moderate growth (~4%), and South Dakota and Kansas minimal impacts (~1.3% and 0.05%, respectively).

Utility projections confirm these trends. Public Service Company of Oklahoma anticipates commercial load to rise 2.7% annually through 2026 due to new large loads, then decline 1.2% per year as efficiency offsets growth (Public Service Company of Oklahoma 2024). Nebraska Public Power District projects that by 2030, demand could exceed the “high-load” scenario by 200 MW, with total additional load surpassing 650 MW driven by new data centers, crypto mining, and hydrogen production (Nebraska Public Power District 2023).

Industry

Industrial electricity demand is set to grow rapidly across the United States, with particularly pronounced near-term growth in the Southeast and Texas, driven by data centers, semiconductor manufacturing, and hydrogen production. New York and PJM are seeing emerging large projects concentrated in upstate/capital regions and select industrial hubs, while California's industrial growth is notable but more distributed. SPP stands out for long-term hydrogen-driven demand, though regulatory and logistical uncertainties could affect the pace of development. ERCOT, Arizona, and Nevada show aggressive industrial growth tied to hydrogen, crypto mining, and EV battery manufacturing, highlighting how regional resource endowments and federal incentives shape load patterns. Overall, industrial load growth is becoming a major driver in specific regions, but the scale and timing vary widely, and uncertainty around hydrogen and other emerging industries underscores the importance of flexibility and grid planning.

New York

New York is entering a new phase of industrial electricity demand. While only a handful of large-scale users—a total of just 310 MW—have connected to the grid since 2005, the next five years could add 3,000 MW through 15 major projects, including factories, data centers, and hydrogen plants. The New York Independent System Operator (NYISO) projects that large load projects could add about 2,567 MW of demand by 2035 (NYISO 2025), mostly in the upstate and Capital regions, with annual electricity use by these large facilities potentially increasing from just over 6,000 GWh in 2025 to more than 10,000 GWh by 2030 under baseline assumptions, and potentially higher in more aggressive growth scenarios (NYISO 2024).

PJM

Industrial-driven load growth in the PJM region is growing. While PJM does not publish a specific figure for industrial load growth alone, the 2025 Long-Term Load Forecast highlights that several major projects are expected to substantially increase load across the region. Examples include a new steel facility in Duke Energy's Ohio/Kentucky territory, electrification of the ports of Bayonne, Elizabeth, and Newark in New Jersey within PSE&G's service area, and a new chip processing plant in AEP's territory (PJM 2025a).

Southeast

Over 200 new transportation and clean energy manufacturing facilities have been announced in the Southeast, representing over $100 billion in investment. States in the region have seen the announcement of over 200 new transportation and clean energy manufacturing facilities, representing more than $78 billion in investment for just the EV and battery manufacturing sectors alone, which speaks to the scale of new industrial development (Vining and Khatib 2025). Georgia and the Carolinas are leading, with 4 GW of industrial load growth expected (Wilson et al. 2025).

For example, Georgia Power's 2025 IRP highlights significant growth in electricity demand driven by both manufacturing and infrastructure support for low-carbon technologies, including data centers, EVs, batteries, and solar panel production. From October 2023 to June 2024, Georgia Power's long-term large load pipeline grew by approximately 6.8 GW, reaching 22.8 GW in total, while 10 new large load projects—representing 7.3 GW of committed demand—formally secured electric service agreements during that period (Georgia Power 2025). Further highlighting the surge in data center development, Georgia's forecasted summer peak load for 2029 has increased by 38% over the past two years, driven overwhelmingly by data centers, which account for 85% of the projected growth (Boyd and Olinsky-Paul 2025).

SPP

Unique to SPP's industrial load growth forecast is the expected expansion of hydrogen electrolysis. The SPP region is particularly attractive for large-scale hydrogen production due to its abundant, low-cost wind resources, supportive federal incentives like the 45Q tax credit, and ample land for infrastructure. SPP's Future Load Scenarios project electrolysis demand growing from zero in 2023 to 235 TWh by 2034, and between 241 TWh (moderate scenario) and 334 TWh (full electrification scenario) by 2050—accounting for about one-third of total electricity consumption. States such as Oklahoma, Kansas, Nebraska, and parts of Texas are expected to lead the way in this expansion (Jones et al. 2024). Thirty-nine percent of the projected U.S. electrolysis load could be economically viable in the SPP region, based on capacity expansion modeling using the Regional Investment and Operations (RIO) model, which considers renewable resource quality and production costs (Southwest Power Pool 2024). Despite this strong growth potential, hydrogen projections for SPP are uncertain due to pending federal regulations on renewable sourcing, grid deliverability, and near-term constraints like supply chain limits and water availability. These factors make the pace and scale of deployment difficult to predict, even with promising long-term prospects. Nonetheless, federal funding is supporting regional hydrogen hubs, such as the Heartland Hydrogen Hub in northern SPP, which could receive up to $925 million and initially focus on fertilizer production and cofiring at power plants. This highlights both the opportunity and uncertainty in the region's hydrogen future.

ERCOT

Texas is forecasted to receive about half of all industrial load growth through 2030 from a combination of battery manufacturing, hydrogen production, crypto mining, oil and gas, and other industrial activities. By 2030, of the projected approximately 138 GW in summer peak demand (Potomac Economics 2025), ERCOT attributes

- 7.5 GW to crypto mining
- 8 GW to hydrogen production
- 7 GW to other industrial activities
- 3 GW to oil and gas exploration and recovery

Specific to ERCOT, the state of Texas has also seen substantial investment from the hydrogen industry, with several large-scale projects underway, which are expected to add flexible, yet substantial amounts of industrial load on ERCOT's grid as more facilities come online.

MISO

MISO's Long-Term Load Forecast projects 5 GW of industrial load growth by 2030 (MISO 2024).

Southwest

Industrial and data center growth are dominant drivers of electricity demand in Arizona and Nevada. Arizona Public Service (APS) forecasts nearly 80% of Arizona's projected 24 GWh increase in annual energy needs between 2023 and 2038 will come from data centers and large industrial facilities, particularly semiconductor manufacturing (Western Electricity Coordinating Council 2025). Nevada has become a hub for EV battery manufacturing, attracting over $15 billion in private investment (Electrification Coalition 2025). Numerous manufacturers, including Tesla—which plans to develop a new gigafactory in the state—have contributed to gigawatt-scale battery manufacturing capacity being developed in Nevada. In New Mexico, electrification of oil, gas, and industrial operations could generate economic impacts of up to $5 billion over five years, speaking to the scale at which industrial electrification is happening in the state (Xcel Energy 2025).

Northwest

Industrial electrification and new manufacturing loads are also substantial in the Northwest, particularly due to chip fabrication, advanced manufacturing, and hydrogen production. Oregon alone produces 40% of the nation's domestically manufactured microchips, and new fabrication facilities, along with hydrogen electrolysis projects, are expected to add substantially to electricity use over the next two decades. The Northwest Power and Conservation Council (NWPCC)'s forecast shows that demand from industrial electrification, combined with data centers, could increase between 1.8% and 3.1% annually through the 2040s. Much of this growth is concentrated in eastern Oregon, eastern Washington, the Portland metro area, and Boise, Idaho.

Transportation

The largest near-term growth in transportation electrification—primarily through electric vehicle (EV) adoption—will occur in California (see figure A3). PJM and the Northeast will also see substantial growth, while the Southwest and SPP face more moderate near-term increases. Critical to integrating these loads without exacerbating peaks will be managed charging programs, such as Salt River Project's goal to control 90% of new EV charging, which highlight the importance of demand-side solutions alongside infrastructure expansion.[49]

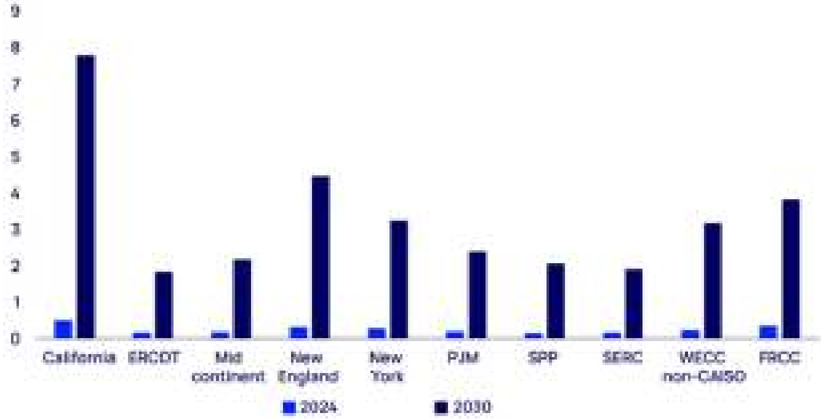

Figure A3. Percentage of electricity EVs consume and are projected to consume in each grid region. Figure sourced from Seiple (2024).

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[49] These projections were compiled prior to the passage of the One Big Beautiful Bill Act that rolled back incentives for EV manufacturing and purchases. This legislation adds significant uncertainty to these projections, which are now more likely to be overestimates.

Northeast

Transportation electrification is going to drive significant load growth in New England. By 2034, EVs are expected to account for 8,735 GWh of annual energy use, surpassing even the projected load from heating electrification (Walton 2025a). Managed charging programs, which help shift EV charging to off-peak hours, are expected to see growing participation, starting at 2% of personal light-duty EV owners in 2025 and reaching 11% by 2034, with further increases anticipated in subsequent years (ISO-NE 2025b). This trend will be crucial for integrating EVs into the grid without exacerbating peak demand challenges.

New York

New York's ambitious climate and clean energy policies are rapidly transforming the state's transportation sector, making EV adoption a major driver of electricity demand growth over the next decade. By 2030, light-duty EVs are expected to account for 42% of all new vehicle sales in New York, surging to 85% by 2035. This rapid transition means the number of EVs on New York's roads will climb from about 1.6 million in 2030 to nearly 4 million by 2035 (Schuler 2024). NYISO forecasts that electricity use from EVs will rise from 2.4 TWh in 2025 to 9.1 TWh in 2030, and then more than double to over 20 TWh by 2035. New York's transportation electrification extends beyond just passenger cars. By 2030, electric buses are projected to make up 87% of new sales, while medium- and heavy-duty EVs are expected to reach a 16% share of new vehicle sales.

PJM

Transportation electrification is expected to have a significant impact on PJM's grid. The forecast anticipates that the load resulting from electric vehicle adoption will surge from about 500 MW today to nearly 13,530 MW by 2034 (Howland 2024).

SPP

Electricity demand from transportation in the SPP region is expected to surge as EV adoption accelerates. Under a baseline scenario, transportation demand rises modestly from 1 TWh in 2023 to 12 TWh by 2050, but in moderate and full electrification scenarios, demand jumps to 73 TWh and 138 TWh by 2050, respectively, making transportation one of the largest and fastest-growing sources of new electricity load—especially as commercial trucks and passenger vehicles shift to electric power (Jones et al. 2024).

MISO

MISO's Long-Term Load Forecast projects 2 GW of load growth from transportation electrification by 2030 (MISO 2024).

Southwest

In the Southwest, utilities have set ambitious EV and charging infrastructure deployment goals. APS projects EVs will add 3,313 GWh of demand by 2038 (APS 2023), while Tucson Electric Power aims to deploy 95,000 light-duty EVs, 800 commercial vehicles, and 2,000 charging ports by 2030. (Tucson Electric Power 2024). Salt River Project plans to support 1 million EVs and manage 90% of charging in its service area by 2035 (Salt River Project 2024). In New Mexico, EVs could require 254 MW of additional capacity by 2030 and 537 MW by 2045 (El Paso Electric Company 2025). Nevada sees similar trends, with Nevada Power and Sierra Pacific projecting combined incremental EV energy sales that will result in roughly 263 GWh of new electricity consumption by 2030 (NV Energy 2021).

CAISO

Transportation electrification is projected to be the largest single contributor to future demand in California. By 2030, 2.4 GW of new transportation load is expected (CEC 2025b). By 2035, 13.7 million passenger zero-emission vehicles (ZEVs) and 407,000 commercial ZEVs will add 4.8 GW of load, with passenger vehicles alone accounting for 3,949 MW. Across the state's major utilities, peak demand is projected to grow sharply: Pacific Gas & Electric by 74% (to 30.7 GW), Southern California Edison by 48% (to 32.6 GW), and San Diego Gas & Electric by 57% (to 6.5 GW) between 2025 and 2035. EVs account for over 60% of this added demand (Kevala 2023).

Buildings

Electrification of buildings—primarily space and water heating—will have regional impacts that vary based on climate, policy, and the pace of technology adoption. Large peak demand increases are expected in California, while building electrification is projected to shift systems to winter peaking in New England and New York. The Northwest could seek significant peak load increases under aggressive gas phase-out scenarios. Future of Gas proceedings in Colorado and Illinois are likely to shift building loads from the gas to the electric system. SPP and MISO show steady growth in building electrification, though this is unlikely to be the primary driver of growth in these regions.

Northeast

The electrification of heating and electric vehicle adoption are reshaping New England's electricity demand. ISO-New England projects annual electricity use to rise 11% over the next decade (ISO New England 2025e), with heating electrification alone increasing from 692 GWh in 2025 to 8,049 GWh by 2034, as shown in table A1 (ISO-NE 2025c). This growth will be seen in every New England state. Massachusetts is likely to experience the most growth, with annual load from heating electrification projected to increase from 257 GWh in 2025 to 3,732 GWh by 2034. This shift is so pronounced that by the mid-2030s, winter peak electricity demand is expected to surpass summer peak.

Table A1. ISO-New England 2025 Heating Electrification Forecast

	Annual Energy (GWh)									
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Connecticut	70	131	199	275	360	458	576	719	884	1,077
Massachusetts	257	478	735	1,028	1,361	1,742	2,181	2,675	3,191	3,732
Maine	188	296	413	539	676	826	996	1,189	1,394	1,610
New Hampshire	38	67	99	134	176	225	280	340	405	479
Rhode Island	25	47	71	98	129	164	207	259	318	387
Vermont	114	168	227	290	358	431	508	590	674	763
Total	**692**	**1,188**	**1,743**	**2,365**	**3,060**	**3,846**	**4,748**	**5,773**	**6,867**	**8,049**

Winter peak demand is projected to rise 36% over the next 10 years across the Northeast, from 20,639 MW in 2025–2026 to 27,981 MW in 2034–2035 (NERC 2024). Unlike traditional summer peaks, which typically occur in the late afternoon, winter peaks often exhibit a dual-peak patterns—one in the early morning (7–9 a.m.) driven by residential heating and water heating, and another in the evening as people return home. These peaks can also persist for extended durations during extreme cold events, posing unique reliability challenges for grid operators (Specian et al. 2021).

New York

Similar to ISO-New England, NYISO anticipates electricity demand to increase by as much as 90% by 2042, primarily driven by heating and transportation electrification (NYISO 2024). As a result of the widespread adoption of heat pumps, the state of New York is also expected to become a winter-peaking state by the mid-2030s (Markham 2024).

California

Building electrification is a central driver of load growth in CAISO. It is expected to add 2 GW of load by 2030 and 5.4 GW by 2035, though behind-the-meter resources could offset nearly 4.800 GW of that growth (CEC 2025b). The California Energy Commission (CEC) projects peak demand will grow 33% in the next decade and 45% over the next 15 years (Mainzer 2025), with overall electricity consumption rising 76% by 2045 compared to 2022 (Hohbein 2025). State policies mandating all-electric space and water heating in new residential (2026) and commercial (2029) buildings support this trajectory.

Northwest

Building electrification could increase peak loads in the Northwest by more than 50% by 2050 if gas use in buildings is phased out, compared to just 8% growth if gas remains in use (Net-Zero Northwest n.d.). While some Northwest cities have taken steps toward electrification, this projection reflects a more aggressive scenario rather than a likely outcome under current policies. While near-term impacts are modest (i.e., 500 average MW by 2030, equivalent to roughly 4.4 TWh annually), consumption from building electrification could reach 2,000 average MW by 2040 (about 17.5 TWh) (Simmons et al. 2025). Oregon illustrates the scale of this shift: Statewide electricity consumption is projected to increase 10–12% by 2030, and 13% by 2050, due to widespread electrification. At the same time, efficiency gains from switching away from electric resistance and to heat pumps are expected to reduce residential peak demand by 17%, offsetting some of the new load (Takahashi et al. 2022).

Appendix B. Select state load flexibility potentials

While there are few, if any, load flexibility programs specifically designed for new large loads like data centers, existing demand flexibility programs have a demonstrated track record of reducing peak demand. As with energy efficiency, demand response (DR) is utilized nonhomogeneously, with some states utilizing it considerably less than others.

In **California**, virtual power plants (VPPs) could meet more than 15% of the state's peak grid load by 2035, saving ratepayers $550 million per year, according to the Brattle Group (Hledik et al. 2024). The grid-data analytics firm Kevala estimated that doubling California's load shift capacity from 3.5 GW to 7 GW by 2030 could reduce distribution system upgrade costs by $3.7–13.7 billion. They found that first reducing the load on the least overloaded distribution system assets to the point that they no longer required an upgrade, then working up the successively overloaded assets from lowest to highest yielded the highest reduction in costs (CEC 2023; Kevala 2025; Walton 2024). Additional examples of current programs and past performance are included in section **Technology priorities and program models.**

The potential of load flexibility to reduce peak demand is being recognized in states throughout the country. One of those states is **Texas**, where the combination of efficiency and load flexibility in residential and commercial buildings could offset almost 15 GW and 25.3 GW of summer and winter peak load, respectively, by 2030. For context, this is enough demand-side resource to offset the capacity of more than 10 new 10 GW gas plants (Nadel et al. 2023).

In **Indiana**, the Northern Indiana Public Service Company's (NIPSCO) integrated resource plan looked at the realistic achievable load flexibility potential from various measures (see B1). NIPSCO found nearly 250 MW of summer DR potential through 2046, enough capacity to offset nearly 19% of their current peak demand, or about 58% of the capacity of a planned gas peaker plant.

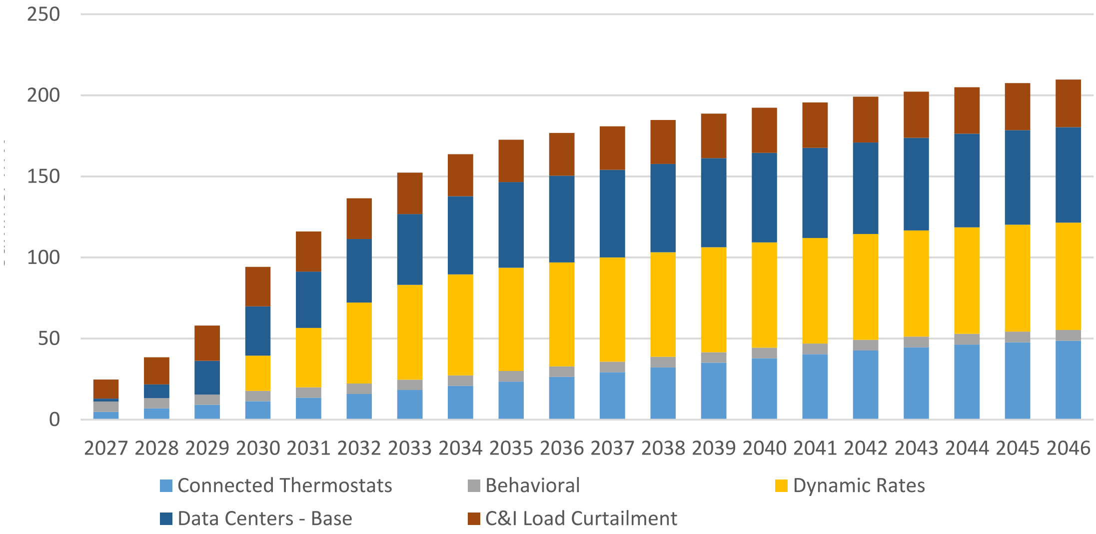

Figure B1. Realistic achievable load flexibility potential by program in NIPSCO. Figure sourced from NIPSCO (2024)).

New York is projected to have 3.0 GW of cost-effective, achievable grid flexibility potential by 2030, enough to cover 11% of the New York Independent System Operator's (NYISO's) summer peak demand. That flexibility potential increases to 8.5 GW in 2040, enough to cover 25% of the state's net system peak demand (i.e., the load not served by renewable energy). As shown in figure B2, one of the largest providers of flexible load reduction is vehicle-to-grid integration either through V1G (a one-way signal from the grid that manages the time, rate, or location of charging) or V2G (which adds the capability of the electric vehicle (EV) sending power back to the grid).[50]

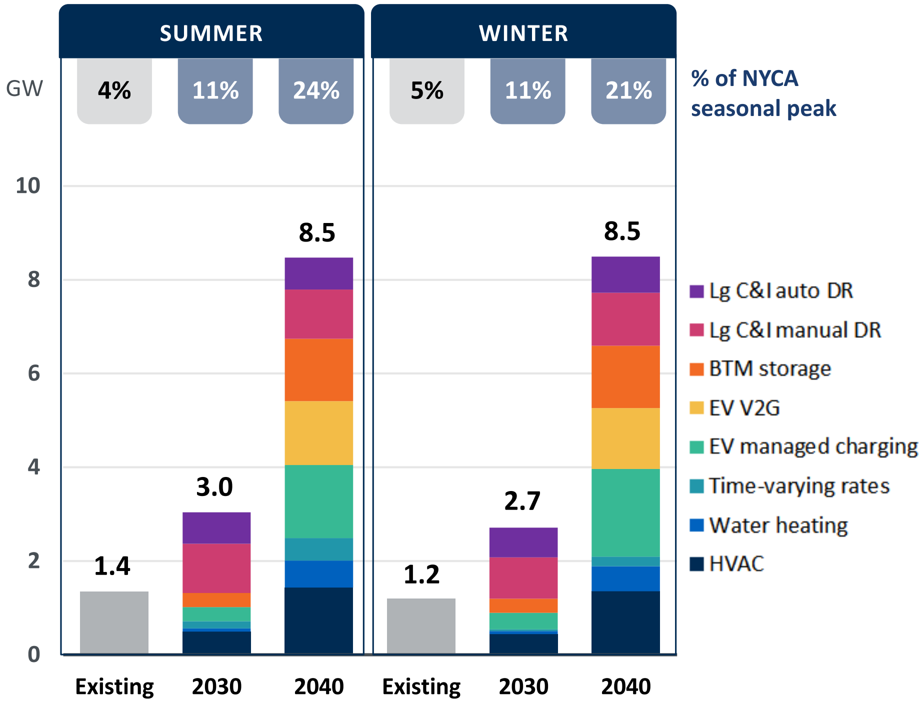

Figure B2. Grid flexibility potential in New York. Figure sourced from Hledik et al. (2025).

The Massachusetts Department of Energy Resources runs the $4.86 million Peak Demand Reduction Grant Program, which is designed to test strategies to reduce energy usage at times of peak demand (Commonwealth of Massachusetts 2025).

Whether you consider the potential of demand-side resources from a national or local perspective, the conclusion is clear. Multiple independent analyses show that demand-side management (DSM) has tremendous potential to meet the loads of the future.

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[50] Descriptions of individual programs are provided in section **Policy and program approaches**.

Appendix C. Cost of energy efficiency and load flexibility

Energy efficiency

We determine the cost of utility energy efficiency (EE) programs primarily through data provided in utilities' annual demand-side management (DSM) reports. We collected data from 52 of the largest U.S. utilities (by retail sales), then compared reported lifetime savings estimates from measures installed in 2024 with the full cost of running those programs in 2024.[51] The resulting data are presented in table C1. For utilities that only report annual incremental savings we derive lifetime savings by applying an average expected useful lifetime (EUL) of 12.45 years, which is the average EUL of the utilities that do report those data. Lifetime savings are measured net at the generator.

Table C1. Energy efficiency program spending and savings data from the largest U.S. utilities in 2024

Utility	EE program spending (2024)	Incremental energy savings (MWh)	Projected lifetime savings (MWh)	Cost of EE ($/MWh)	EE peak demand reduction (MW)
Georgia Power Co.	$64,190,663	425,662	5,299,448	$12.11	74.72
Duke Energy Indiana, LLC	$29,056,670	189,787	2,362,828	$12.30	25.20
Southern California Edison Co.	$207,659,253	1,305,400	16,295,100	$12.74	279.30
Arizona Public Service Co.	$69,021,393	425,092	5,187,591	$13.31	336.60
Niagara Mohawk Power Corp. (National Grid NY)	$62,331,026	374,940	4,667,964	$13.35	—
Entergy Texas Inc.	$8,344,034	46,303	576,470	$14.47	26.31
Wisconsin Electric Power Co.	$89,492,530	364,383	6,131,370	$14.60	51.08
CPS	$35,362,039	185,646	2,311,274	$15.30	44.50
Commonwealth Edison Co.	$435,219,509	1,653,073	27,618,215	$15.76	236.57
CenterPoint Energy TX	$45,471,984	229,003	2,851,063	$15.95	233.00
Public Service Co. of Colorado (Xcel)	$94,100,000	466,830	5,811,986	$16.19	65.79
Nevada Power Co.	$38,609,214	234,996	2,365,606	$16.32	65.09
Duke Energy Carolinas	$151,076,530	683,333	8,507,423	$17.76	999.20

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[51] These utilities serve approximately 79 million residential customers, representing about 60% of all U.S. households. Utilities were selected to match those analyzed as part of ACEEE's *Utility Energy Efficiency Scorecard* (Specian et al. 2023).

Utility	EE program spending (2024)	Incremental energy savings (MWh)	Projected lifetime savings (MWh)	Cost of EE ($/MWh)	EE peak demand reduction (MW)
Entergy Louisiana, LLC	$17,800,819	79,457	989,231	$17.99	12.20
Entergy Arkansas, LLC	$58,231,942	251,696	3,133,589	$18.58	80.00
Northern States Power Co. – Minnesota (Xcel)	$119,627,167	516,246	6,427,210	$18.61	106.81
Salt River Project	$55,200,000	626,020	2,927,356	$18.86	157.24
AEP Texas Central	$16,666,699	70,899	882,682	$18.88	62.90
PacifiCorp	$66,751,153	391,999	3,408,070	$19.59	46.71
Baltimore Gas & Electric Co.	$189,573,846	735,758	9,160,110	$20.70	600.00
DTE Electric Company	$196,000,000	919,000	9,463,156	$20.71	148.92
Oklahoma Gas & Electric Co.	$39,757,554	182,909	1,913,911	$20.77	31.36
Duke Energy Progress	$79,858,517	305,745	3,806,488	$20.98	133.97
Oncor	$52,807,719	196,624	2,447,948	$21.57	66.67
MidAmerican Energy Co.	$43,977,916	160,018	1,992,209	$22.07	40.87
San Diego Gas & Electric Co.	$81,007,424	278,580	3,387,670	$23.91	58.60
Consolidated Edison Co.–NY, Inc.	$83,758,256	274,058	3,411,993	$24.55	—
Ameren Illinois Company	$155,416,341	438,825	6,186,908	$25.12	60.48
West Penn Power Company (First Energy)	$25,733,000	74,758	956,833	$26.89	4.38
Consumers Energy Co.	$199,500,829	664,676	6,976,121	$28.60	85.30
Duke Energy Florida, LLC	$19,891,000	55,723	693,746	$28.67	15.65
Los Angeles Department of Water & Power	$125,162,948	295,701	4,218,416	$29.67	72.20
Florida Power & Light Co.	$31,456,000	84,658	1,053,977	$29.85	36.08
PECO Energy Co.	$104,427,000	275,698	3,422,794	$30.51	51.89

Utility	EE program spending (2024)	Incremental energy savings (MWh)	Projected lifetime savings (MWh)	Cost of EE ($/MWh)	EE peak demand reduction (MW)
Virginia Electric & Power Co. (Dominion)	$244,000,000	621,096	7,996,768	$30.51	116.00
Dominion Energy South Carolina, Inc. (previously South Carolina Electric & Gas)	$26,089,302	65,673	817,622	$31.91	16.43
PPL Electric Utilities Corp.	$57,198,000	194,667	1,778,043	$32.17	29.78
Tampa Electric Co.	$46,761,898	108,700	1,353,304	$34.55	22.10
Portland General Electric Co.	$132,827,232	296,360	3,689,645	$36.00	37.80
Pacific Gas & Electric Co.	$169,811,505	341,900	4,256,619	$39.89	59.80
Puget Sound Energy Inc.	$142,383,257	258,145	3,213,878	$44.30	—
Union Electric Co.–(MO) (Ameren Missouri)	$74,760,166	111,388	1,522,602	$49.10	43.14

Several large utilities were excluded from the energy efficiency analysis. These include the Ohio utilities—Ohio Power Co., Duke Energy Ohio, and Ohio Edison Co.—that had their energy efficiency programs canceled as part of H.B. 6 in 2019. Alabama Power was excluded due to a lack of available data. Three utilities that run very successful DSM programs—Eversource Massachusetts, Eversource Connecticut, and National Grid Massachusetts—were also excluded due to the fact that we were unable to disaggregate spending and savings data from combined efficiency and electrification measures in time for publication.

Utilities' DSM reports also provide measures of peak demand reduction achieved as a result of energy efficiency programs. These values are also provided in table C1. As shown in figure C1, there is an approximately linear relationship between incremental energy savings and peak demand reduction, such that **for each GWh saved, utility energy efficiency programs simultaneously achieve about 0.2 MW of peak demand reduction.** Outliers—Duke Energy Carolinas and Baltimore Gas and Electric—are excluded from this linear regression even though they reported far greater peak demand reduction per GWh than the rest of the utility cohort.

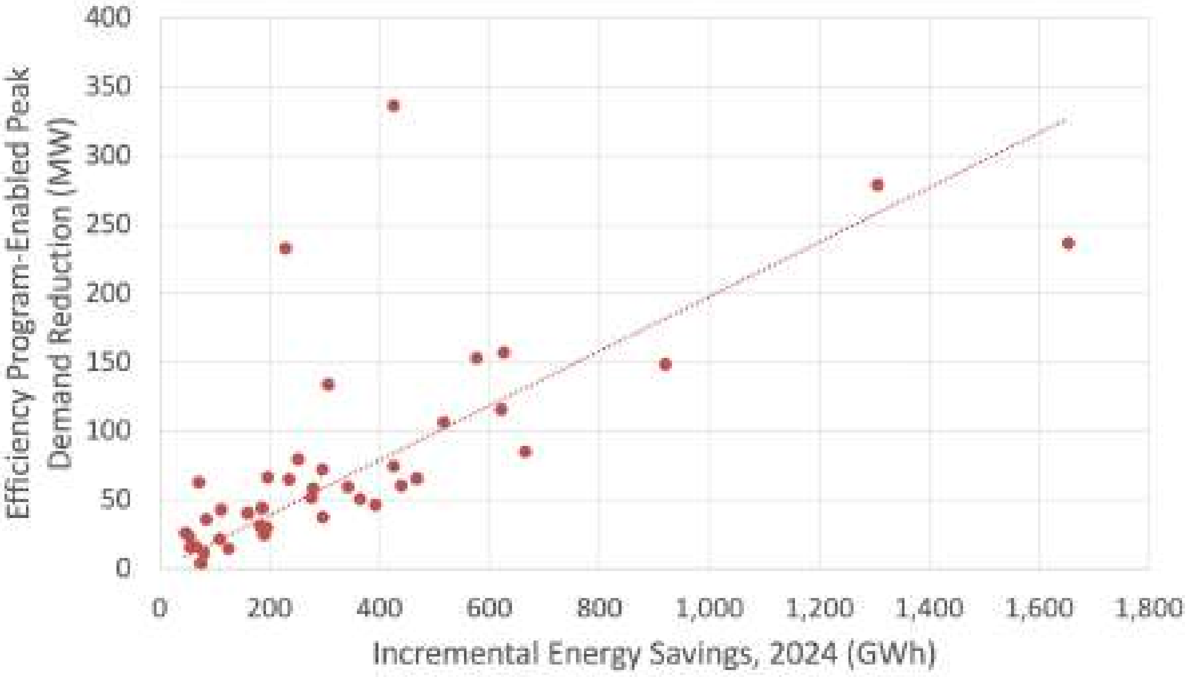

Figure C1. Relationship between incremental energy savings and peak demand reductions achieved as a result of utility energy efficiency programs in 2024.

To derive the peak demand reduction achieved via energy efficiency programs, we use the realistic annual electricity consumption reduction estimate of 365 TWh by 2040 (Holmes et al. 2019). Each TWh of annual savings results in approximately 200 MW of peak demand reduction, which means 365 TWh of annual energy savings leads to about 73,000 MW of peak reduction. Langevin et al. (2021) project a technical potential for EE of 742 TWh and 800 TWh in 2030 and 2050, respectively. We average these values to estimate a technical potential of 771 TWh in 2040, which would yield a peak reduction of 154,200 MW.

A wide variety of energy efficiency measures are eligible to be counted as part of efficiency program savings. These include

Residential measures

- **High-efficiency consumer electronics:** Promoting the purchase and use of high-efficiency consumer electronics, including through rebates, midstream and upstream programs, and the use of smart strips with consumer electronics (relocated from emerging program areas).
- **Home appliances:** Incentivizing the sale, purchase, and installation of appliances (e.g., refrigerators, dishwashers, clothes washers and dryers) that are more efficient than current standards.
- **Home energy audits:** In-person or virtual survey of customer's home to determine where energy is being lost, including recommendations for actions the resident can take to improve their home's efficiency.
- **Home retrofit:** Combining a comprehensive energy assessment or audit that identifies energy savings opportunities with house-wide improvements in air sealing, insulation and, often, HVAC systems and other end uses.

- **HVAC equipment:** Incentivizing the sale/purchase and installation of heating, cooling, and/or ventilation systems at higher efficiency than current energy performance standards, across a broad range of unit sizes and configurations.
- **HVAC tune-up:** Incentivize tune-ups that restore the energy performance of HVAC systems; measures in this category include those that correct issues related to thermostats, air filtration, fan blades, blower motors, coils, drainage, wiring and connections, circuit boards, voltage supply, refrigerant leakage, and duct connections.
- **Lighting:** Encouraging the sale/purchase and installation of more efficient lighting in the home. These programs range from point-of-sale rebates to mailings or giveaways. Measures tend to be LED lamps, fixtures, and holiday lights and lighting controls, including occupancy monitors/switches and daylighting controls.
- **Multifamily:** Encouraging the installation of energy efficient measures in common areas, units, or both for residential structures of more than four units.
- **Smart thermostats:** Increasing energy-efficient behaviors through smart thermostats. Includes learning thermostats, Wi-Fi-enabled thermostats, grid-connected thermostats, and other smart thermostat programs.
- **New construction:** Providing incentives and possibly technical services to ensure new homes are built or manufactured to energy performance standards higher than applicable code.
- **Heat pump water heaters:** Incentivizing the purchase of electric heat pump water heaters, either standalone or included as part of another program.
- **Weatherization readiness:** Actions taken to address health, safety, or structural issues in homes that would otherwise preclude efficiency measures (e.g., envelope retrofits). Includes direct utility action or connecting customers with non-ratepayer funded programs.
- **Solar hot-water heater:** Incentives for the purchase or installation of an ENERGY STAR certified solar water heater.
- **Behavior-based/feedback:** Reducing energy consumption through social science theories of behavior change by providing information to customers, by leveraging interpersonal interactions, or by providing consumer education. Excludes programs that rely on traditional program strategies such as incentives, rebates, or regulations.
- **Appliance recycling:** Removing less efficient appliances (typically refrigerators and freezers) from households.
- **Education:** Providing education on energy efficiency to students, not including marketing programs.

Commercial and industrial measures

- **Lighting:** Incentivizing the installation of efficient lighting including high-efficiency lamps and fixtures.
- **Lighting system and control:** Incentivizing lighting occupancy monitors/switches and daylighting controls.
- **HVAC:** Encouraging the sale/purchase and installation of heating, cooling, and/or ventilation systems at higher efficiency than current energy performance standards, across a broad range of unit sizes and configurations.
- **Efficient motor systems:** Incentivizing improvements to motor systems, including installation of adjustable speed drives, optimization of pump and fan systems, and compressed air system controls.
- **Retrocommissioning:** Diagnosing energy consumption in a commercial facility and optimizing its operations to minimize energy waste. Program activities tend to be characterized by tuning or retuning, coordinating, and testing the operation of existing end-uses, systems, and equipment for energy efficient operation.
- **Whole-building retrofit:** Combining a comprehensive energy assessment or audit that identifies energy savings opportunities with building-wide improvements in air sealing, insulation, and, often, HVAC systems and other end uses.
- **New construction:** Providing incentives or technical services to ensure new commercial buildings are built or manufactured to energy performance standards higher than applicable code.
- **Strategic energy management:** Managing energy through continual improvement and a systematic approach to energy performance, including a commitment through policies, goals, and allocation of resources; energy management planning and implementation; and a system for measuring and reporting performance.
- **Custom:** Delivering site-specific industrial and commercial projects typically characterized by an extensive onsite energy assessment and identification and installation of multiple measures unique to that facility.
- **Small business:** Offering energy efficient measures to retail, grocery, small offices, convenience stores, and other nonresidential customers with electric demand below 100 kW. Can include direct install or other delivery models.
- **Kitchen and restaurants**: Offering energy-efficient measures for commercial food service equipment.
- **Field agriculture:** Offering incentives for energy-efficient farm field- and orchard-based equipment such as irrigation pumping.
- **Data centers:** Incentivizing measures to improve data center energy efficiency, such as through high-efficiency cooling systems, servers, and other equipment.
- **School and government:** Programs specifically tailored to educational facilities and publicly-owned buildings.

Other programs

- **Code compliance:** Funding or operating a program to improve compliance with building energy codes, typically through training activities.
- **Conservation voltage reduction or volt/voltage and reactive power (VAR) optimization:** Improving the efficiency of a utility's transmission and distribution system through voltage reduction systems, whether explicitly included in the utility's energy efficiency portfolio or not.
- **Controlled environment agriculture:** Measures that lower energy use in controlled agricultural facilities, including lighting and environmental control systems.
- **Cool roofs:** Measures that increase the reflectivity (albedo) of roofs in order to reduce heat flow from the roof into the occupied building space.
- **Distribution transformers:** Installing more efficient transformers on the distribution system.
- **Energy-efficient fuel switching:** Encouraging fuel switching that delivers overall source Btu energy savings, greenhouse gas (GHG) reductions, and customer cost savings.
- **Energy use feedback to consumers in real time:** Allowing consumers to better understand their energy usage behavior and react to increase savings. Includes programs that provide feedback in near real time. Typically requires advanced metering infrastructure (AMI) installation.
- **Geo-targeting:** Targeting residential, commercial, or industrial buildings in specific geographic locations that will yield high savings. Does not include geo-targeted marketing efforts or comparative home energy or business energy report programs.
- **GHG reductions:** Programs designed specifically to reduce GHG emissions through means other than direct reductions in energy consumption, for example, tree planting, refrigerant management.
- **Grid-interactive efficient buildings:** Incentivizing buildings that reduce energy waste and carbon emissions while offering flexible building loads to the grid. May include integrating energy efficiency and load flexibility to better value the many benefits of grid-interactive efficient buildings.
- **Industrial process electrification:** Incentivizing measures that replace fossil-fueled industrial technologies with more efficient electric alternatives including industrial heat pumps, infrared heating, radio frequency or microwave heating, electric boilers or hot-water heaters, and onsite hydrogen production.
- **Heat pumps:** Incentivizing the adoption of cold- or warm-climate heat pumps with heating seasonal performance factor (HSPF) above 10. Must provide extra incentives for advanced heat pumps relative to those provided for moderate-efficiency heat pumps.
- **High-efficiency ceiling fans:** Promoting the installation of high-efficiency ceiling fans, either stand-alone or included as a part of another program.
- **High-efficiency residential clothes dryers:** Offering rebates for high-efficiency clothes dryers that meet the ENERGY STAR Most Efficient specification (e.g., heat pump dryers).
- **Midstream programs:** Transforming the market for energy-efficient products by targeting midstream retailers and partners to improve choices and reduce costs for consumers. Includes midstream lighting, high-efficiency HVAC, heat pump water heater, and appliance programs.

- **Net-zero energy buildings:** Promoting zero-energy buildings through incentives, technical assistance, codes and standards or other methods. Could also include a tiered approach, such as a zero-energy "step codes." Does not include participation in zero net energy forums or coalitions.
- **Programs using data disaggregation:** Extracting end-use and/or appliance-level data from an aggregate or whole-building energy signal to engage consumers and to target relevant programs to specific customers. This can also include in-home devices that disaggregate end uses at the meter and provide feedback to customers via an app or web interface.
- **Quality HVAC installation:** Improving and ensuring the quality installation of HVAC equipment, such as incentivizing installation to American National Standards Institute (ANSI)/Air Conditioning Contractors of America (ACCA) Standard 5.
- **Reduction of plug and other miscellaneous load in commercial buildings:** Reducing plug or other loads in commercial buildings, including midstream and upstream programs for equipment like advanced power strips (tiers one and two) and smart plugs.
- **Window treatments:** Passive window coverings or attachments that reduce heat transfer between the interior and exterior environments including interior shades and drapes, films applied directly to glass, exterior shades, shutters, awnings, and storm windows.

Load flexibility

We determine the effective demand reduction costs of supply-side resources in table 3 using data from Lazard's "Levelized Cost of Energy" report from June 2024 (Lazard 2024). We translate lifetime CapEx costs ($/kW) into CapEx costs per year by dividing the former by the average facility lifetime. Fixed annual operations and maintenance (O&M) costs are subsequently added in to generate a total effective cost in terms of $/kW-year.

These values represent the cost of demand reduction assuming the resource is fully available during peak demand periods, which is not the case for any generation type. Therefore, we scale the costs upward based on the effective load carrying capability (ELCC) of each generation resource. ELCC is a measure of how much an energy resource contributes to system reliability during peak demand periods. It is measured as a percentage of the resource's nameplate capacity. Cost values and ELCC assumptions are provided in table C2.

Table C2. Effective cost of peak demand reduction from supply-side resources. Cost and facility life data sourced from Lazard (2024).

Energy Type	CapEx, low ($/kW)	CapEx, high ($/kW)	Facility life (years)	CapEx, low ($/kW-year)	CapEx, high ($/kW-year)	Fixed O&M, low ($/kW-year)	Fixed O&M, high ($/kW-year)	ELCC	Effective cost, low ($/kW-year)	Effective cost, high ($/kW-year)
Wind–onshore	$1,300	$1,900	30	$43.33	$63.33	$24.50	$40.00	17.00%	$399.02	$607.84
Solar PV–utility	$850	$1,400	35	$24.29	$40.00	$11.00	$14.00	36.80%	$95.89	$146.74
Gas combined cycle	$850	$1,300	20	$42.50	$65.00	$10.00	$25.50	80.00%	$65.63	$113.13
Wind+Storage–onshore	$1,355	$2,000	20	$67.73	$100.00	—	—	65.00%	$104.19	$153.85
Solar PV–community and commercial and industrial (C&I)	$1,300	$2,900	30	$43.33	$96.67	$13.00	$20.00	36.80%	$153.08	$317.03
Solar PV+Storage–utility	$891	$1,474	20	$44.55	$73.70	—	—	61.50%	$72.44	$119.84
Geothermal	$4,860	$6,280	25	$194.40	$251.20	$14.50	$15.75	95.00%	$219.89	$281.00
Coal	$3,310	$7,005	40	$82.75	$175.13	$40.85	$94.35	74.00%	$167.03	$364.16
Wind–offshore	$3,750	$5,720	30	$125.00	$190.67	$60.00	$91.50	17.00%	$1,088.24	$1,659.80
Gas peaking	$700	$1,150	20	$35.00	$57.50	$10.00	$17.00	87.00%	$51.72	$85.63
U.S. nuclear	$8,765	$14,400	40	$219.13	$360.00	$136.00	$158.00	97.50%	$364.23	$531.28

Of the 52 utilities considered, 32 provide cost and demand reduction data from their load flexibility programs. These data are summarized in table C3.

Table C3. Load flexibility program costs and peak demand reductions achieved through utility demand response (DR) programs in 2024

Utility	DR Spending	DR peak demand reduction (MW)	Cost of DR ($/kW-year)
Arizona Public Service Co.	$1,299,735	196.20	$6.62
DTE Electric Company	$11,406,539	657.00	$17.36
MidAmerican Energy Co.	$6,619,043	258.11	$25.64
Salt River Project	$4,239,909	164.60	$25.76
Entergy Texas Inc.	$317,652	8.83	$35.97
CenterPoint Energy TX	$6,678,306	173.98	$38.39
Georgia Power Co.	$2,897,046	72.51	$39.96
Oncor	$6,495,801	157.66	$41.20
PacifiCorp	$16,946,254	384.00	$44.13
Duke Energy Carolinas	$47,155,108	882.55	$53.43
Long Island Power Authority	$4,270,000	65.87	$64.82
CPS	$12,320,345	182.84	$67.38
Duke Energy Indiana, LLC	$5,935,399	84.50	$70.24
Consolidated Edison Co.–NY, Inc.	$59,026,800	766.94	$76.96
Consumers Energy Co.	$50,763,537	654.80	$77.53
Duke Energy Progress	$6,248,290	78.40	$79.70
Connecticut Light & Power Co. (Eversource CT)	$8,165,815	100.00	$81.66
Jersey Central Power & Lt Co. (First Energy)	$2,128,000	26.00	$81.85
Northern States Power Co.–Minnesota (Xcel)	$16,023,561	187.54	$85.44
Union Electric Co.–(MO) (Ameren Missouri)	$16,960,457	174.79	$97.03
Nevada Power Co.	$19,668,027	180.72	$108.83
Virginia Electric & Power Co. (Dominion)	$6,087,354	52.98	$114.90
Baltimore Gas & Electric Co.	$35,607,925	219.20	$162.44
Massachusetts Electric Co. (National Grid MA)	$13,223,023	75.70	$174.67
NSTAR Electric Company (Eversource MA)	$13,702,783	69.48	$197.22
Public Service Co. of Colorado (Xcel)	$21,300,000	101.76	$209.32
Entergy Arkansas, LLC	$10,667,787	33.60	$317.49
Pacific Gas & Electric Co.	$33,495,380	96.00	$348.91
San Diego Gas & Electric Co.	$12,243,746	6.52	$1,877.88
Florida Power & Light Co.	$76,385,000	29.04	$2,630.34
Tampa Electric Co.	$26,571,700	7.48	$3,552.37
Duke Energy Florida, LLC	$89,372,000	23.52	$3,799.83

No ELCC adjustment is needed because peak demand reductions reflect load reduction achieved, not load reduction capacity.

We determine the rate that utility energy efficiency programs can scale up by comparing their lifetime savings achieved by incremental measures installed in three-year intervals between 2015 and 2024 (see table C4). We choose three years as the comparison duration since many energy efficiency resource plans are developed, funded, and evaluated every three years, so this duration helps smooth out year-to-year variance, such as large changes that might result from utilities loading savings to the back end of a triennium.

Table C4. Lifetime savings (MWh) of select fast-growing utility energy efficiency programs

Utility	State	Lifetime savings (2015)	Lifetime savings (2018)	Lifetime savings (2021)	Lifetime savings (2024)	Average annual growth rate	Year range
CenterPoint Energy	TX	1,675,401	1,509,830	3,413,305	2,851,063	31.24%	2018–2021
Duke Energy Carolinas (NC)	NC	3,022,642	6,412,551	3,189,830	8,507,423	28.49%	2015–2018
Duke Energy Carolinas (SC)	SC	1,116,098	2,372,051	1,146,054		28.57%	2015–2018
Duke Energy Indiana	IN	778,988	1,840,973	1,085,339	2,362,828	33.20%	2015–2018
Duke Energy Ohio	OH	1,287,202	2,536,226	1,610	—	25.37%	2015–2018
Entergy Louisiana	LA	278,292	101,070	888,241	989,231	106.37%	2018–2021
Georgia Power	GA	1,081,072	4,727,708	4,276,805	5,299,448	63.53%	2015–2018
PPL Electric Utilities	PA	1,778,786	3,156,574	2,455,644	1,778,043	21.07%	2015–2018
Public Service Elec & Gas	NJ	2,933,197	2,300,255	5,197,458	7,304,418	31.22%	2018–2021
San Diego Gas & Electric	CA	3,015,737	5,448,060	8,094,708	3,387,670	21.79%	2015–2018
Tampa Electric	FL		355,321	2,429,259	1,353,304	89.79%	2018–2021
Virginia Electric & Power	VA	1,294,703	688,373	1,718,973	7,996,768	50.49%	2018–2024
West Penn Power	PA	755,847	1,479,600	741,635	956,833	25.09%	2015–2018

Data for all years was acquired via utility DSM reports and data requests made directly to utilities. Methodologies for data acquisition are detailed in ACEEE's *Utility Scorecard* reports (Relf et al. 2017, 2020; Specian et al. 2023).

Appendix D. Additional policy approaches and program examples

This appendix contains supplemental information about current responses to load growth and examples of demand-side programs that are being used to address it.

Current responses to load growth

New gas generation

Utilities in Arizona, Georgia, Indiana, Louisiana, Nebraska, Nevada, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and Virginia have all proposed new gas-fired plants, which have been approved or are under review by the respective state public utility commissions (PUCs). Arizona Public Service's 2023 Integrated Resource Plan (IRP) includes new gas capacity, and Georgia Power's 2023 and recently approved 2025 IRP call for major additions, including 268 MW of new natural gas capacity at Plant McIntosh, upgrades of up to 400 MW at existing gas and nuclear facilities, and the extended operation of a gas plant in Alabama to supply electricity to Georgia (Georgia Power 2025). Dominion Energy Virginia's IRP calls for nearly 6 GW of new gas infrastructure by 2036, a plan in conflict with the Virginia Clean Economy Act, which requires the utility to procure 100% carbon-free electricity by 2045 (Clean Virginia 2024; Virginia Clean Economy Act 2020). In August 2025, Entergy's plan to spend billions of dollars on new gas generation to serve a Meta data center was approved by Louisiana regulators (Peters 2025).

Over 100 GW of new gas-fired projects have now been announced. Excluding small projects and those without completion dates, around 120 gas-fired plants are planned by 2030 for a total of roughly 80 GW—over two times the 35 GW added in the past five years (Shenk 2025). The geographic spread of this buildout is closely correlated with new data center projects. Of these 80 GW, about 25 GW comes from vertically integrated utilities, while 15 GW each is planned in PJM, ERCOT, and MISO, with the remaining 10 GW distributed across other regions.

Delaying fossil-fuel retirements

Many utility IRPs across the United States include provisions to extend the operational life of existing fossil-fuel plants, including both natural gas and coal, in response to surging electricity demand from data centers and other large loads. States including California, Georgia, Indiana, Illinois, Louisiana, Maryland, Nebraska, Nevada, New York, North Carolina, Ohio, Tennessee, Texas, Michigan, and Virginia have all moved to extend plant operations. For example, California has postponed gas plant closures in response to extreme weather and reliability concerns, while Illinois extended the Baldwin coal plant's retirement due to MISO reliability needs (Vistra Corp. 2024). In the Southeast, Georgia Power's 2025 IRP keeps coal plants like Plant Bowen and Plant Scherer operating into the mid-2030s, reversing earlier retirement plans.

In addition to these requests from utilities, recent mandates from the federal government have directed certain retiring fossil plants to remain online, often outside of traditional regulatory approval processes. Keeping these plants running has significant emissions and cost implications: nationwide, federal mandates to retain retiring fossil plants could cost U.S. electricity consumers between $3.1 billion and $5.9 billion per year by 2028. The states with the highest potential annual costs include California ($389 million), Texas ($183 million), Colorado ($178 million), Michigan ($171 million), Louisiana ($164 million), and Illinois ($161 million) (Goggin 2025). Many of these states are already experiencing rapid load growth, and without a greater focus on efficiency and demand-side management (DSM), both federal mandates and utility plans to extend fossil plant operations are likely to further increase costs for consumers.

Onsite renewables

Several states have taken action that would require data centers to procure or generate a significant portion of their needed energy from onsite renewable sources.

- **West Virginia, H.B. 2014 –** On April 30, 2025, the governor of West Virginia signed H.B. 2014 into law. The law establishes a Certified Microgrid Program that enables large energy users, including data centers, to develop and operate onsite clean energy systems with minimal regulatory oversight. The law allows these facilities to form microgrids, generate renewable energy, and manage their own electricity distribution without approval by local governments or utility commissions. By streamlining permitting and supporting energy self-sufficiency, H.B. 2014 aims to attract data centers and other high-load facilities while promoting investment in clean, resilient power infrastructure (West Virginia Office of the Governor 2025).
- **New Jersey, S.B. 4143 –** This bill would require data centers to run entirely on renewable or nuclear power, taking effect only after the New Jersey Board of Public Utilities (BPU) determines that a majority of states in the PJM Interconnection region have adopted similar standards. Once triggered, AI data center developers must submit an energy usage plan to the BPU detailing how the facility will meet the clean energy requirement, optimize cooling and water use, and repurpose waste heat (Smith and McKeon 2025).
- **Minnesota, H.F. 2928 (did not pass) –** Had it passed, H.F. 2928 would have required data centers to procure at least 65% of their power from renewables before 2030 and 100% after 2030. Compliance would be tracked on an hourly basis, ensuring they match their real-time energy use with renewable generation (Minnesota House of Representatives 2025).
- **Virginia, H.B. 2578 - (did not pass) –** This proposed Virginia bill would have tied the state's sales and use tax exemption for data centers to stricter clean energy and efficiency standards. By 2030, data centers would have needed to source a portion of their electricity from renewable energy and invest in energy efficiency (EE). The bill also sought to impose stricter emissions limits on backup generators by 2027 due to health concerns in nearby communities. It called for state agencies to study alternatives to diesel generators and explore options for reusing waste heat, with findings due by the end of the year. Although it did not pass, the bill illustrates how state legislatures are beginning to consider stronger efficiency requirements for data centers (Sullivan 2025).

Electric rates

To address the risks and potential cost shifts associated with large new loads like data centers, several states are introducing policies that govern how data centers connect to and impact the grid. Georgia, Indiana, Maryland, Nevada, North Carolina, Ohio, Oregon, Texas, and Virginia are creating special rates, cost-sharing mechanisms, or requirements to ensure large customers pay their fair share and to protect other ratepayers, particularly low-income customers who stand to be the hardest hit by cost increases. These policies focus on tariff structures, infrastructure cost recovery, and reliability obligations, rather than the operational efficiency of data centers and large loads. Another policy mechanism some states are exploring is cost allocation, which aims to ensure that the financial burden of new infrastructure or grid upgrades is borne by large load customers rather than shifted to ratepayers. Here are some examples:

- **Georgia Public Service Commission –** In January 2025, the Georgia Public Service Commission took concrete steps to address the impact of new large electricity loads by approving a rule requiring customers with loads exceeding 100 MW to cover the full costs of transmission and distribution infrastructure needed to serve them. The rule also permits longer contract lengths, up to 15 years, and minimum bill requirements, ensuring that if a data center stops operating before the contract ends, it still pays for the infrastructure investments made on its behalf (Georgia Public Service Commission 2025).
- **Texas S.B. 6 –** Signed into law in June 2025, S.B. 6 requires new large electricity users (≥75 MW) to pay for their own interconnection costs—including study and transmission screening fees—rather than shifting those costs to other ratepayers. These customers must report onsite backup generation that can serve at least 50% of demand, which ERCOT can require them to deploy during grid emergencies to curtail their load once market options are exhausted. Facilities that interconnect after December 31, 2025, must also include remote disconnect ("kill switch") capability to allow load-shedding control during ERCOT-declared grid emergencies (S.B. 6 2025)
- **American Electric Power (AEP) Ohio Data Center Tariff –** In July 2025, the Ohio Public Utilities Commission approved a dedicated tariff for new large data centers proposed by AEP Ohio. It applies to customers with peak loads over 25 MW, requiring them to pay for at least 85% of contracted electricity capacity each month to recover infrastructure costs, even if usage is lower. The tariff mandates a 12-year service contract with a four-year ramp-up (minimum payments rising from 50% to 90% of capacity) followed by an eight-year commitment at 85%. Early termination triggers exit fees. Data centers must also demonstrate financial viability and provide collateral (a cash deposit, bond, or letter of credit) that the utility can draw on if the customer fails to meet its obligations, and they must cover 100% of grid upgrade costs—shielding other ratepayers from subsidies (AEP Ohio 2025).
- **Virginia H.B. 2084 –** Signed into law in March 2025, this bill directs the State Corporation Commission to evaluate whether electric utility rates and customer classifications are reasonable, including whether new or separate classes are needed to ensure large customers, such as data centers, pay their fair share without shifting costs to other ratepayers (H.B. 2084 2025).
- **North Carolina H.B. 1002 –** Enacted in April 2025, H.B. 1002 ensures that utilities cannot shift the costs of serving large commercial data centers, 100 MW or larger, onto other retail ratepayers. All infrastructure and service costs reasonably attributable to these data centers must be recovered directly from the data centers themselves (Ratepayer Protection Act 2025).

- **Nevada –** In 2024, the Nevada PUC approved the Clean Transition Tariff, proposed by Google and NV Energy, which enables large electricity customers to purchase 100% clean energy directly through NV Energy. The tariff is designed to support the development of new renewable energy resources while protecting other utility ratepayers from added costs (Penrod 2024).
- **Oregon –** H.B. 3546, or the POWER Act (Protecting Oregonians with Energy Responsibility), was signed into law on June 16, 2025. The law is designed to prevent residential and small business customers from subsidizing the grid costs created by large industrial users, which have driven up rates in recent years. It creates a new regulatory framework for large energy use facilities—primarily data centers and cryptocurrency operations. Electric companies must enter into long-term contracts (minimum 10 years) with large energy use facilities, specifying service details, projected usage, and minimum payment obligations. The Oregon Public Utility Commission must establish a separate service classification and electric rate schedule for these large users, ensuring their electricity costs are allocated fairly and do not unfairly burden other consumer classes. The PUC must submit biennial reports to the legislature on trends and implications of large energy use facilities' electricity consumption. The law sunsets January 2, 2035 (POWER Act 2025).

Data transparency

States are increasingly requiring data centers to share energy-related data. Here are some additional examples:

- **California Distribution Deferral Investment Framework –** This framework includes a grid needs assessment (GNA) that occurs before identifying and ranking deferral opportunities for distribution system investments. The California PUC (CPUC) has stated that "a main purpose of the GNA is to provide transparency into the assumptions and results of the distribution planning process that yield the candidate deferral shortlist" (California Public Utility Commission 2018; Schwartz et al. 2024).
- **California A.B. 222 –** California has introduced a bill that would require data center owners to submit their power usage effectiveness ratio to the CPUC, and require the CPUC to report on the projected future load trends from data centers and the potential net peak load demands (A.B. 222 2025).
- **Illinois S.B. 2181 –** Illinois legislators have proposed that data centers annually report their energy consumption by month and energy source, as well as any measures taken during the previous year to improve energy efficiency. The bill would also require the Illinois Power Agency to conduct a comprehensive study on the impact of data centers on ratepaying customers, including effects on electricity demand, rate changes, and environmental implications (Illinois Data Center Energy and Water Reporting Act 2025).

Demand-side management (DSM)

States are also targeting the efficiency and load flexibility of data centers. Policy proposals include requiring large electricity users to participate in EE, demand response (DR), workforce, or community development programs or to fund such initiatives as a condition of their grid connection or to gain access to other benefits; allowing new large loads to interconnect faster if they agree to curtail their load when the grid is constrained; requiring load centers to adhere to explicit quantitative targets for energy savings or demand reduction; and encouraging or requiring the aggregation of distributed energy resources (DERs) into virtual power plants (VPPs). Descriptions of some of these policies are listed below.

DSM/Efficiency standards

- **California –** California stands out as the most stringent state in regulating data center energy use. The CPUC mandates compliance with Title 24 of the California Energy Code, which sets standards for energy efficiency, renewable energy use, and carbon footprint management in data centers. Facilities must meet specific requirements for efficient HVAC systems, adopt energy-saving technologies, and participate in load flexibility programs.

  The California Energy Commission (CEC) has adopted load management standards designed to increase statewide demand flexibility by requiring its large energy utilities and community choice aggregators (CCAs) to abide by the following four requirements (CEC 2026):

  - Along with the CEC, maintain the accuracy of existing and future time-varying rates in the publicly available and machine-readable Market Informed Demand Automation Server (MIDAS) rate database.
  - Develop a standard rate information access tool to support third-party services.
  - Develop and submit locational rates that change at least hourly to reflect marginal wholesale costs.
  - Integrate information about new time-varying rates and automation technologies into existing customer education and outreach programs.

- **Texas, S.B. 2888 – (did not pass) –** This bill would have added energy conservation and efficiency measures to tax exemption requirements for data centers, specifically mentioning the use of ENERGY STAR-certified servers as a qualifying technology. The goal was to ensure that data centers benefiting from tax incentives are deploying best-in-class, energy-efficient equipment (Texas Senate Bill 2888 2025).
- **Virginia H.B. 116 – (did not pass) –** This bill would have required data center operators to meet certain energy efficiency standards in order to be eligible for the sales and use tax exemption for data center purchases. Facilities would have to demonstrate a power usage effectiveness (PUE) ≤ 1.2, be among the 15% most efficient similar facilities, or meet at least 90% of its energy requirements from carbon-free electricity (Virginia H.B. 116 Retail Sales and Use Tax; Exemption for Data Centers 2024).

Recent state-level efforts have explored linking energy performance requirements for data centers to tax incentives or permitting, in some cases making efficiency upgrades a factor in eligibility for financial benefits. However, examples remain limited and vary widely across jurisdictions. There is a strong focus on advanced cooling technologies and high-density readiness to handle AI-driven workloads, alongside mandates for transparency through energy and emissions reporting. Overall, these policies reflect a trend toward integrating data center development with broader clean energy, decarbonization, and community impact goals, while rapidly evolving to keep pace with the sector's explosive growth. Table D1 outlines several state policy actions to improve data center efficiency.

Table D1. Select state policy actions related to improving data center efficiency

State	Policy	Description	Status
Colorado	S.B. 25-280	Large data centers and new load projects can qualify for tax incentives by meeting energy efficiency standards and achieving LEED or ENERGY STAR certifications, while utilities coordinate on investments and costs are prevented from shifting to ratepayers (Data Center Development and Grid Modernization Act 2025).	Did not pass
Washington	E.O. 25-05	Governor's order establishes a data center workgroup to develop recommendations on energy efficiency, water use, and environmental performance standards for data centers (State of Washington Office of Governor Bob Ferguson 2025)	In effect
New York	S. 6394	Required data centers to report on energy use, emissions, water consumption, and environmental impacts, and tasks state agencies, including the New York Power Authority (NYPA) and New York Independent System Operator (NYISO), to develop energy efficiency goals for data centers that emphasize waste heat recycling; specific efficiency goals have not been identified (Senate Bill 6394 2025).	Did not pass
Georgia	S.B. 34	Would prohibit shifting grid upgrade costs for data centers to ratepayers, incentivizing investment in efficiency and grid-friendly design; also considering rules for reliability and cost allocation.	Did not pass

While recent efforts suggest a trend toward linking efficiency and clean energy goals to incentives, most state policies remain limited in scope, often relying on existing green building certifications, or attempting to incentivize efficiency indirectly through mechanisms like tax benefits or cost allocation. Few policies require measurable operational metrics (e.g., PUE) that directly track efficiency, meaning the full value of efficiency is often overlooked. As a result, efficiency is undervalued, even though it can provide faster, cheaper, and more impactful energy and resource savings compared with other approaches.

Policies encouraging grid contributions and efficiency/public benefit investments

Beyond cost recovery, some states have also explored requirements for data centers to contribute to energy efficiency programs that benefit low-income utility customers, invest in workforce and infrastructure, and provide transparency through public reporting—all aimed at ensuring data centers act responsibly.

- **Minnesota, H.F. 16 –** On June 14, 2025, H.F. 16 was signed into law, requiring data centers to contribute $2–5 million to support energy efficiency programs for low-income households. It also extends certain tax exemptions for data centers that meet efficiency and water use standards (H.F. 16 2025). The policy uses existing green building certifications for data centers—within three years of being placed in service, data centers designed to have a load of 100 MW or more must achieve certification in one or more of the following standards: Building Research Establishment Environmental Assessment Method (BREEAM) (new construction or in-use), ENERGY STAR, Envision, ISO 50001, LEED (building design or operations and maintenance (O&M)), Green Globes, or UL 3223. These standards include requirements for data centers to meet energy efficiency benchmarks, including PUE, and to focus on the efficiency of computing components.
- **Colorado S.B. 25-280 (see table D1) –** In addition to establishing proposed data center efficiency requirements, S.B. 25-280 would have required data centers seeking tax incentives to invest in workforce development or other community benefit programs, as well as a minimum $10 million investment in grid enhancement and modernization.
- **Pennsylvania House Bill 1843 –** The Data Center Act would establish a fund (Data Center LIHEAP Enhancement Fund) for low-income energy assistance, funded by annual payments from data centers according to the following schedule:
    - 25–75 MW: $250,000
    - 75–100 MW: $400,000
    - >100 MW: $500,000

  Any public utility contracting with a commercial data center must ensure that at least 25% of the electricity supplied under the contract comes from renewable energy sources (solar, wind, biomass, or hydroelectric). Neither of these provisions directly references EE, but they are philosophically consistent with EE as a solution. We recommend replacing the energy assistance fund with an EE fund, as the latter is a longer-lasting solution. We also recommend that EE be counted as a renewable energy source. The bill was referred to the Committee on Energy on September 4, 2025 (House Bill No. 1834 - Data Center Act 2025).

EE and DSM Requirements

The use of DSM, DERs, and (more recently) aggregating these into VPPs to meet growing load demand in the U.S. is accelerating, but remains in its early stages. Most existing VPP programs have been developed through utility-led initiatives or regulatory mandates that extend traditional load flexibility or load flexibility programs, rather than through explicit state legislation.[52]

Only a handful of states, most recently Virginia, Maryland, and Colorado, have passed laws requiring utilities to establish or propose VPP programs. The majority of states, however, are in earlier phases of exploration, often passing policies that encourage utilities to integrate DSM as a core component of VPPs—using tools to reduce or shift electricity demand—rather than focusing solely on supply- or storage-based resources. These policies typically focus on assessing the potential of these technologies rather than mandating full-scale program development, pointing to a landscape where actual VPP deployment is still limited but the foundation for growth is being laid.

- **Virginia H.B. 2346/S.B. 1100 –** In 2025, the Virginia Legislature enacted H.B. 2346, requiring Dominion Energy to launch a VPP program aggregating up to 450 MW of distributed energy resources, including residential smart thermostats, batteries, and electric vehicles (EVs). The law directs Dominion to dedicate at least 15 MW to residential battery incentives, prioritize participation from low-income and disadvantaged communities, and pilot a school bus-to-grid initiative. The law requires Dominion to petition the State Corporation Commission, which regulates utilities, for the pilot by December 1, 2025, and to propose a program tariff for residential, commercial, and industrial customers by November 15, 2026. Following the pilot's conclusion on July 1, 2028, the commission must evaluate the effectiveness of the pilot programs in providing grid services during times of peak demand and begin developing a permanent program (H.B. 2346 2025).
- **Georgia H.B. 1192 –** This bill would have required the Georgia Public Service Commission to consider creative approaches to manage data center usage including variable load, efficiency, and backup generation. The bill was passed by the House and Senate in early 2024, but was vetoed by the governor on May 7, 2024 (Georgia H.B. 1192 2023).
- **Maryland H.B. 1257/S.B. 959 (DRIVE Act) –** Passed by the Maryland General Assembly in May 2024, the Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act requires utilities to enable bidirectional EV charging, meaning they must install and operate systems that allow vehicles to both draw power from the grid and supply electricity back. Utilities are also required to run pilot programs that compensate EV owners for providing grid services. The law directs the Public Service Commission (PSC) to issue interconnection regulations by May 2025, requires investor-owned utilities (IOUs) to design and submit VPP programs by July 2025 to the PSC, and expands time-of-use rates to encourage off-peak charging (Gribbins 2024).

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[52] Another strategy is the "bring your own virtual power plant" (BYOVPP) program that enables customers—often large commercial and industrial (C&I) users—to aggregate and leverage their own DERs to support grid reliability and manage peak demand. Participants in a BYOVPP program can enroll their resources to provide grid services with the goal of enhancing grid flexibility, reducing the need for costly infrastructure upgrades, and ensuring that the costs and benefits of grid support are fairly allocated among participants and other ratepayers (Allsup 2025).

- **Colorado S.B. 24-218 –** The "Modernize Energy Distributions Bill" was signed into law by the Colorado governor in May of 2024, requiring large IOUs to invest in programs that expand grid flexibility and DSM, including options for phased or flexible customer interconnections, improved planning for hosting distributed energy resources, and proactive engagement with disproportionately impacted communities. The law also mandates that these utilities establish a VPP program by February 2025, with a performance-based tariff that compensates customers for deploying distributed energy resources—such as solar, batteries, and EVs—to provide grid-supportive services and help meet Colorado's electrification and decarbonization targets (Modernize Energy Distribution Systems Act 2024).

Developing new supply-side infrastructure is increasingly becoming more costly and slow—VPPs provide a faster, more cost-effective alternative to reduce peak demand. VPPs can deliver peak capacity at 40–60% of the cost of traditional gas peaker plants, saving billions for utilities and ratepayers. Policymakers should prioritize energy efficiency and load flexibility programs that provide flexible load management, requiring IOUs to design and implement these initiatives as key strategies to manage load growth while advancing clean energy and grid modernization.

Regional transmission organization proposals for large load interconnection

Regional transmission organizations (RTOs) are beginning to explore ways to accommodate the rapid load growth expected from data centers, including through new market rules and planning initiatives. Several have already proposed or implemented.

- **PJM – Non-Capacity Backed Load (NCBL) Proposal –** In August 2025, PJM proposed a rule that would create a new service category allowing large new loads to interconnect under curtailable conditions when the grid is constrained. These loads would not pay capacity market charges but would still contribute to transmission planning and costs. The proposal is designed to help PJM accommodate rapid load growth without inflating capacity market prices. The proposal remains under stakeholder review, with a Federal Energy Regulatory Commission (FERC) filing targeted for late 2025 (Bresler and Horger 2025).
- **SPP – Conditional High Impact Large Load (CHILL) Proposal –** SPP's CHILL proposal would allow large customers to connect to the grid faster by using nonfirm transmission service, meaning they can use available transmission capacity but may be curtailed during system stress events. Customers could mitigate this risk by deploying contracted or colocated generation or storage. In exchange for accepting a mandatory "curtail or lose" obligation for up to five years, large customers could avoid the long delays typically associated with new transmission development. SPP withdrew this proposal in August 2025 and is expected to introduce an updated version before the end of the year (Sharma Frank 2025)

Program examples

Load flexibility programs open additional grid headroom and reduce capacity requirements, making them a crucial component of cost-effectively addressing load growth. This chapter contains multiple examples of DR program types and case studies of specific programs currently run by utilities across the United States. These case studies showcase initiatives that are actively supporting grid reliability and customer engagement. The range of programs includes both incentives for purchasing enabling technologies and payments or bill credits for actual load flexibility participation.

HVAC

Home energy upgrades in Ohio

The AnnDyl policy group analyzed the costs and benefits of offsetting data center load growth in Ohio with building-focused DSM. They quantified the cost to achieve energy, demand, and GHG reductions as well as annual customer savings; the number of projects needed to offset peak demand, annual energy, and annual GHG from a 200 MW data center; and the benefits of a $50 million investment that fully covers upgrade costs for low-income households. They find that the combination of insulation, air/duct sealing, and smart thermostats offer the optimal balance of positive outcomes. Their methodology can be replicated to quantify benefits in other states (Saul Rinaldi and Presley 2025).

PGE residential DR programs

Portland General Electric's (PGE) residential DR offerings focus on using smart thermostats to reduce HVAC usage during periods of peak demand. These programs invite customers with qualifying HVAC systems, such as central air-conditioning, electric forced-air furnaces, or ducted heat pumps, to enroll their eligible Internet-connected thermostats, such as Nest, ecobee, or Honeywell products, for automated participation. During a load flexibility event, PGE sends a signal to participating devices, instructing them to make temporary adjustments to their heating or cooling setpoints.

Events usually last anywhere from 1–4 hours, and thermostat adjustments are relatively modest (typically 1–2°F). To maintain comfort, homes are precooled or preheated in advance of the event when possible. Customers are notified before each event and can override the change at any time (PGE n.d.b).

Independent evaluations have found that the program consistently delivers around 1 to 1.2 kW of reduced demand per household during events (Cadmus 2021). Because participation has surpassed tens of thousands of customers, the cumulative impact of this thermostat program can reach over 100 MW of load reduction during critical periods. This represents a meaningful contribution to grid stability during hot summer days or cold winter mornings. Participating customers receive one-time financial incentives for enrolling in the program, as well as seasonal incentives for participation when customers allow their thermostat to respond to at least 50% of event hours each season.

PGE commercial and industrial (C&I) DR programs

Like the residential program, PGE's Energy Partner Smart Thermostat program targets business customers with ducted electric heating and/or air-conditioning systems but focuses exclusively on smart thermostat control rather than building-wide systems. Eligible commercial customers—ranging from small businesses to larger commercial sites—can enroll either by bringing their own Wi-Fi-enabled qualifying smart thermostat or by receiving a free professionally installed unit through PGE.

During peak time events, the participating thermostats automatically adjust heating or cooling setpoints by a few degrees to reduce energy use temporarily, then return to normal settings once the event concludes. Like residential customers, business participants retain full control and can override adjustments as necessary.

The commercial program offers a $100 up-front enrollment incentive for customers who bring their own qualifying thermostats. Additionally, businesses receive $60 for each DR season they participate in (summer and winter), as long as they avoid overriding thermostat control for more than 50% of event hours (PGE n.d.a).

This alignment in design and technology ensures that a broad customer base—including homes and businesses—can participate easily in load flexibility, leading to substantial, scalable reductions in HVAC electricity use during critical periods.

Case study—PGE load flexibility programs

PGE operates a well-developed set of DR programs that serve both residential and commercial customers. These programs are designed to better manage electric demand during system peaks, reduce stress on the grid, and give customers opportunities to save energy and earn financial incentives. Rather than relying on one-size-fits-all solutions, PGE has developed separate offerings tailored to the needs and capabilities of households and businesses—particularly with a focus on controlling HVAC loads, which account for a significant portion of electric usage in both sectors.

Smart thermostat load flexibility potential

The U.S. Department of Energy's (DOE's) Virtual Power Plants Liftoff Report notes that North America currently has 33 GW of flexible VPP capacity, largely driven by residential smart thermostat load flexibility programs. Looking ahead, smart thermostats are projected to provide the majority of the 40 GW of additional capacity available from new load flexibility programs. When combined with expanded conventional programs and market transitions—such as advanced metering infrastructure (AMI) deployment, EV adoption, and increased renewable integration—smart thermostats could contribute substantially to a total national load flexibility increase of up to 83 GW by 2030, representing a 140 % increase over existing DR capability (Hledik et al. 2019).

Numerous examples of successful smart thermostat DR programs exist including:

- CenterPoint Indiana's Smart Cycle program enrolled over 8,500 participants by 2024, achieving average demand reductions of 0.94 kW per thermostat. This provided up to 4.64 MW of load relief during grid events and exceeded 11 MW during extreme heat (Cadmus 2025).

- California's 1.6 million smart thermostats have the potential to deliver estimated peak reductions ranging from 66 to 427 MW, depending on participation in time-of-use billing (Blonz et al. 2021).
- Pacific Gas and Electric's (PGE&E's) SmartAC program, which now has more than 100,000 participants, recently delivered an estimated 40 MW of load shift in a single event. According to program reporting, that level of reduction is roughly equivalent to the instantaneous demand of about 30,000 homes, underscoring the scale at which smart thermostats can support grid reliability during peak periods (PG&E 2023).

These examples demonstrate the significant energy savings and peak demand reductions that smart thermostats enable, a crucial capability as building electrification is contributing to dominant load growth in specific parts of the country. By leveraging automated thermostat control and load flexibility, utilities can achieve multimegawatt load reductions cost effectively and at scale. This enhances grid reliability, reduces operational costs, and has the potential to reduce the need for costly infrastructure upgrades to meet growing demand, making smart thermostats a key strategy for managing increasing electricity demand.

Water heating

In 2018, the Bonneville Power Administration (BPA) and PGE launched a regional pilot program in the Pacific Northwest to test whether residential electric water heaters could serve as flexible, low-cost grid resources. The project was designed to help utilities manage the growing variability of renewable energy by shifting water heating to periods when wind and solar generation were abundant and reducing consumption during peak demand hours. As states across the region moved toward higher renewable energy targets, utilities needed new strategies to maintain grid reliability without investing in costly new infrastructure.

Program design

Funded through BPA's Technology Innovation Project 336, the pilot was the largest of its kind in the region. It included 277 residential participants served by eight utilities across Oregon and Washington, including PGE, Clark Public Utilities, and Puget Sound Energy. Over 220 days, the program conducted more than 600 load flexibility events to measure how effectively connected water heaters could shift or shed electrical load.

Two types of water heaters—electric resistance and heat pump models—were equipped with the CTA-2045 communication standard, which allows appliances to receive and respond to real-time grid signals. Using FM radio and Wi-Fi communications, the utilities could automatically adjust water heater operation to align with grid conditions. Customers were not notified before DR events, allowing for accurate assessment of the technology performance under real-world circumstances.

Energy and demand savings

The pilot demonstrated that smart water heaters could reliably provide measurable load reduction and energy shifting, confirming their potential as distributed energy assets. During winter morning peaks, electric resistance units reduced consumption by an average of 374 watts per unit, while heat pump models shed 223 watts. This direct reduction in peak demand provided utilities with valuable capacity relief at times of highest system stress.

The program also showed significant energy shifting capability. During four-hour DR events, electric resistance water heaters shifted up to 1,324 Wh of energy per unit, while heat pump models shifted 507 Wh. In emergency response tests, resistance heaters shed up to 562 watts per unit and heat pump models 244 watts, demonstrating rapid, reliable responsiveness to grid needs.

Customer comfort was largely unaffected. Eighty percent of participants reported being "very satisfied," while 94% said they would participate again. The average opt-out rate was only 4% across all events, even with multiple DR events per day. Hot-water complaints were rare and mostly unrelated to the pilot itself.

Savings and impact

Economic analysis conducted as part of the pilot evaluation revealed strong cost savings potential. If deployed at scale throughout the region, connected water heaters could provide 301 megawatts of peak capacity by 2039—equivalent to the output of a small power plant. This would generate an estimated $106 million in avoided capacity costs, yielding a benefit-cost ratio of 1.74, which rises to 2.45 with direct load control. The aggregated storage potential ranged between 340 and 800 MWh, depending on the season and water heater type. The emissions impact was also significant. By aligning water heating with renewable generation, the program could reduce approximately 115,000 tons of carbon dioxide annually by 2039. If expanded nationwide, similar programs could deliver an estimated $2 billion in cumulative benefits, while reducing reliance on fossil-fueled peaking generation.

The BPA and PGE pilot demonstrates that connected water heaters can serve as reliable, cost-effective, and customer-friendly load flexibility resources. By transforming common household appliances into controllable grid assets, utilities can reduce peak demand, shift energy use to periods with high renewable energy availability, and avoid costly infrastructure investments. The strong technical performance, consistent customer satisfaction, and clear economic value demonstrated in this pilot highlight the potential of smart water heaters to integrate flexible loads into a clean, resilient electric grid.

Thermal energy networks (TENs)

Data centers are beginning to utilize thermal energy networks (TENs) to improve the efficiency of surrounding buildings. In Espoo, Finland, Microsoft is building a data center that will supply heating to about 100,000 homes, eliminating the need for a coal-fired heating plant. In Mäntsälä, Finland, a 75-megawatt data center uses pipes and pumps to transfer waste heat to about two-thirds of the town's homes (Paulsson et al. 2025). The United Kingdom (UK)-based company Deep Green plans to a build a 24-MW data center in Lansing, Michigan, that will loop waste heat into the local water system to provide free, carbon-neutral heat for downtown buildings (Vela 2025).

Storage

Illinois Clean and Reliable Grid Affordability (CRGA) Act

CRGA (Senate Bill 25) mandates the procurement of 3 GW of battery storage by 2030, with procurements to be conducted by the Illinois Power Agency (IPA) in 2027 and 2028. Additional procurements may occur if the state's integrated resource planning process authorizes more storage above the initial 3 GW (CRGA Act 2025). CRGA was passed by the Illinois General Assembly in late October 2025; Governor J.B. Pritzker signed it in January 2026.

Case study–Green Mountain Power Resiliency Zones

Vermont's largest electric utility, Green Mountain Power (GMP), is a national leader in deploying distributed battery storage, microgrids, and VPPs. These technologies drive both demand reduction and grid resilience, which are particularly important as Vermont faces more frequent extreme weather and ongoing load growth.

Resiliency Zones

GMP's Resiliency Zones (RZs) target communities most vulnerable to outages, focusing on rural and high-risk areas. In these zones, GMP partners with towns to deploy solar and battery storage systems—sometimes as microgrids—so residents and critical facilities stay powered during grid outages. Notable projects include microgrids in Panton, Grafton, and Rochester, as well as storage deployments in mobile home parks (Gyuk et al. 2022).

These batteries not only provide backup power but also reduce peak demand on the main grid by discharging stored energy during high-cost, high-demand periods. This approach directly lowers system-wide expenses and supports DSM goals. By aggregating thousands of distributed batteries, GMP is creating a virtual power plant that can be dispatched to support the grid during peak events or emergencies, providing flexibility and reliability without relying on fossil-fuel peaker plants.

Battery deployment and capacity

- As of 2025, GMP has deployed more than 70 MW of battery storage across its service territory, including both residential and utility-scale batteries (Giles 2025).
- The utility's home battery programs have supported deployment of over 7,000 residential batteries, representing 35 MW of capacity.
- GMP's evaluation of their VPP battery network proves that the deployed technologies have deferred transmission and distribution investments, and that with continued adoption, flexible capacity from DERs (including EV chargers), residential energy storage, grid-scale storage, and commercial flexible loads could reach over 30% of projected peak load by 2030 (GMP 2024).

Savings and impact

- Annual savings: GMP's battery and VPP programs save customers about $3 million annually by reducing the need to purchase expensive power during peak demand periods (Howland 2023)
- Peak event example: During a single heatwave week in July 2022, GMP's home battery fleet helped avoid approximately $1.2 million in costs by discharging stored energy at peak times (GMP 2022).
- Demand reduction: By "shaving" peaks, batteries help lower GMP's power supply costs, which are set by the highest-demand hours each month. This reduces reliance on fossil-fuel peaker plants and helps keep rates lower for everyone.
- Resilience: Batteries and microgrids provide seamless backup power, keeping homes and critical facilities running during outages, and supporting vulnerable communities.
- Scalability: The success of these pilots has led GMP to plan for three new RZs per year, with GMP's Zero Outages Initiative (ZOI) aiming for even broader coverage.

GMP's RZs and ZOI demonstrate how distributed batteries, microgrids, and VPPs can deliver both resilience and demand-side management. With more than 70 MW of installed battery capacity and plans to nearly double that, GMP is reducing peak demand, saving millions annually, and supporting vulnerable communities—a replicable model for utilities facing climate-driven outages and the challenges of a cleaner, more electrified grid.

EVs

This section contains multiple examples of EV programs that can be used to manage load growth. These programs are broadly organized into three categories: managed charging programs, voluntary programs or those that offer passive financial incentives, and V2G bidirectional charging programs. More detailed descriptions of each of these programs can be found on these organizations' websites or within these reports: (Alliance for Transportation Electrification 2023; Blair et al. 2023; Fitzgerald and Dougherty 2021; Ghosh 2025)

Managed charging programs

The programs in table D2 use incentives, direct control, smart charging, or telematics to manage when and how EVs charge.

Table D2. EV managed charging program examples

Program	Description
American Electric Power – Kyte Works EV Home Charging Program	Incentivizes residential customers to install and use home EV chargers with managed charging features
Baltimore Gas and Electric – Smart Charge Management Pilot	A multiphase pilot using vehicle telematics and smart charging to optimize grid impacts, offer customer incentives, and test cyber risk mitigation for residential, commercial fleet, and public charging customers, with flexible opt-out options and targeted credits
Baltimore Gas and Electric – EVsmart (managed charging)	Provides incentives and education for EV owners, including managed charging options for residential and fleet customers

Program	Description
Barron Electric Cooperative – Electric Vehicle Charging Station: Energy Efficiency Rebate	Offers rebates for energy-efficient EV charging stations to promote smart charging practices
Con Edison – SmartCharge New York	The nation's largest managed EV charging program, offering cash rewards to residential customers for off-peak and summer peak avoidance charging, using smart chargers or vehicle telematics, with a straightforward enrollment and dashboard interface
Consumers Energy – PowerMIDrive™ Program	A Michigan program combining whole-house time-of-use (TOU) rates, charger rebates, and a "Bring Your Own Charger" option, using AMI data analytics to monitor compliance and offering monthly rebates for off-peak charging. The PowerMIFleet pilot encouraged off-peak charging through TOU rates, resulting in over 85% of fleet charging occurring during off-peak hours in 2022–2023, and ~91% in 2024, leading to its approval as a permanent program
CPS Energy – FLEXEV Smart Rewards and Off-Peak Rewards	Pilot programs for residential customers offering bill credits for allowing remote adjustments to Wi-Fi chargers or for charging during off-peak hours, coordinated by a third-party platform, with measurable load shifting and customer opt-out flexibility
Delaware Electric Cooperative – Beat the Peak	Incentivizes EV owners to shift charging to off-peak times, helping reduce grid stress
Delmarva Power – EVsmart (managed charging)	Provides incentives and education for EV adoption and managed charging
Dominion Energy – EV Charger Rewards	Rewards customers for participating in managed charging and shifting EV charging to off-peak periods
DTE Energy – Charging Forward	Offers rebates for EV chargers and supports managed charging to benefit the grid
Duke Energy Florida – Off-Peak Charging Credit	A residential program offering a $10 monthly bill credit for charging during off-peak periods, verified via vehicle telematics, with limited opt-outs and annual enrollment caps
Duke Energy North Carolina – Residential Subscription Program	A pilot where customers pay a flat monthly fee for unlimited managed charging, with dynamic rates, original equipment manufacturer (OEM) partnerships for telematics, and utility-managed charging events, subject to usage limits
Eversource – EV Home Charger Demand Response	Incentivizes residential customers to allow demand response events via their EV chargers
Green Mountain Power – eCharger Program	Rebates for in-home EV chargers and encourages participation in managed charging
Hawaiian Electric Company – Smart Charge Hawaii	Provides free EV charging stations and promotes managed charging for residents and businesses
Los Angeles Department of Water and Power – Charge Up LA!	Offers rebates for home and workplace EV chargers to encourage off-peak charging
Marin Clean Energy – MCEv	Supports EV drivers with incentives and education for managed charging and grid-friendly practices

Program	Description
Massachusetts Municipal Wholesale – Scheduled Charging Program	Incentivizes scheduled EV charging to align with grid needs and reduce peak demand
National Grid – Connected Solutions	Rewards EV owners for participating in demand response and managed charging
Orange & Rockland – Charge Smart Program	Provides incentives for smart charging and supports grid optimization through managed EV charging
Pacific Gas & Electric – Business Electric Vehicle (BEV) Rate	A commercial subscription service with separate metering, allowing customers to select subscription levels and pay TOU volumetric rates, eliminating demand charges and providing predictable billing and significant savings
Pacific Gas & Electric – emPower EV	Supports residential EV adoption with incentives for managed charging
Pacific Gas & Electric – EV Charge Network (load management plan)	Includes a load management plan to optimize charging station usage and grid benefits
Platte River Power Authority – Smart Electric Vehicle Charging Study	Studies smart EV charging to inform future managed charging programs
Portland General Electric – Business EV Charging Pilot Program	Incentivizes businesses to install and manage EV charging stations for fleets and employees
Portland General Electric – Residential EV Smart Charging	A residential pilot using smart chargers and vehicle telematics to shift charging away from peak times, with seasonal bill credits, opt-out options, and special provisions for Tesla owners
Rocky Mountain Power – EV Charging Station Grant and Rebate Program	Provides grants and rebates for EV charging stations to promote managed charging
Salt River Project – Plug In and Save EV Rebate	Offers rebates for EV chargers and encourages off-peak charging
Salt River Project – SmartCharge Arizona	Incentivizes EV owners to optimize charging times for grid benefits
San Diego Gas and Electric – Power Your Drive	Supports workplace and multiunit dwelling EV charging with managed charging incentives
Snohomish County Public Utility District – SmartCharge	Rewards EV owners for smart charging practices
Sonoma Clean Power – GridSavvy	Encourages EV owners to participate in managed charging for grid reliability and renewable integration
Southern California Edison – Charge Ready Program	Offers incentives for installing EV chargers and supports managed charging
Southern California Edison (SCE) – Honda SmartCharge Program	In partnership with SCE, rewards EV owners for charging when grid conditions are optimal
Xcel Colorado – Charging Perks Pilot	A residential smart charging pilot using OEM and third-party telematics to dynamically optimize charging for off-peak, low-cost, and high-renewable periods, with upfront and ongoing incentives and flexible override options

Voluntary programs or passive financial incentives

The programs in table D3 offer rebates, incentives, or passive financial rewards for EV adoption or off-peak charging, without direct control.

Table D3. Examples of voluntary EV programs or those that offer passive financial incentives

Program	Description
American Electric Power – EV Charging Incentive Program	Offers financial incentives for installing EV charging stations to accelerate adoption and support grid management
Avista – Residential Electric Vehicle Charging Equipment Program	Encourages residential customers to install EV chargers by offering rebates and supporting managed charging
Consumers Energy PowerMIFleet Program	Encouraged off-peak charging through TOU rates, resulting in over 85% of fleet charging occurring during off-peak hours in 2022–2023, and ~91% in 2024, leading to its approval as a permanent program
Delmarva Power – EVsmart (incentives and education)	Provides incentives and education for EV adoption and managed charging
Pacific Gas & Electric Business EV Rate Plan	Replaced demand charges with a TOU rate and a monthly subscription charge, allowing fleet customers to pay a fixed monthly fee based on their chosen charging level and benefit from lower off-peak rates outside of 4–9 p.m.
Pepco – EVsmart	Provides incentives and education for managed EV charging in its service territory

Vehicle-to-grid (V2G), vehicle-to-building (V2B), and bidirectional charging programs

The programs in table D4 involve bidirectional energy flow, allowing EVs to discharge electricity back to the grid or a building.

Table D4. Examples of V2G and V2B programs

Program	Description
Con Edison Electric School Bus V2G Pilot (White Plains, NY)	Piloted V2G operations on three electric school buses, finding that V2G discharge could generate enough utility bill credits to surpass charging costs by $4,000, despite reliability challenges due to hardware and software issues
Consolidated Edison (ConEd) – Bidirectional Capable Systems	Bidirectional-capable systems can interconnect to the grid and participate in the Value of Distributed Energy Resources (VDER) tariff for multiple value streams
Dominion Energy (VA) – Electric School Bus Fleet V2G Program	Electric school bus fleet V2G program providing grid services and resilience, with Dominion owning V2G rights after 15 years
Duke Energy – V2G Pilot (Ford F-150 Lightning)	V2G pilot with Ford F-150 Lightning leases, reducing payments for customers who allow their vehicles to support the grid during peak times
Eversource – ConnectedSolutions Demand Response (V2G discharge)	ConnectedSolutions demand response program compensates customers for EV discharge during grid events
Massachusetts School Bus V2G Pilot (National Grid, Highland Electric, Synop)	A V2G school bus pilot discharged nearly 11 MWh over 158 hours, generating $23,000 in revenue for the school district by sending electricity back to the grid during peak periods
National Grid MA – V1G/V2G Demand Response Program	V1G/V2G demand response program allowing bidirectional-capable EVs to participate in grid events for compensation
New Hampshire Electric Co-op – Transactive Energy Rate	Transactive energy rate enables customers to perform energy arbitrage with bidirectional charging systems
North Boulder Recreation Center (CO) – Commercial V2B Project	Commercial V2B project focused on peak demand savings for the recreation center
Pacific Gas & Electric – V2X Pilots (CA)	V2X pilots across residential, commercial, and microgrid customers, with incentives for participation and a focus on disadvantaged communities
Plymouth State University (NH) – Commercial V2B Project	Commercial V2B project utilizing a transactive energy rate to optimize energy use and costs
Revel Rideshare V2G Project (NY)	Commercial fleet V2G program that participates in demand response rates to support grid flexibility
San Diego Gas & Electric School Bus V2G Project	School bus V2G project required buses to send electricity back to the grid between 4–9 p.m. from May to October, paying $2 per kWh during load emergency response events
Xcel Energy (CO) – Commercial V2B Systems	Commercial customers use V2B systems to reduce peak demand and save on monthly charges

Xcel Energy deep dive

This section provides details on programs offered by a single utility, Xcel Energy.

Case study – Xcel Energy residential and commercial charging programs

Load flexibility program participation in Colorado is relatively high. As of 2022, 15% of residential customers and 45% of large C&I customers were enrolled in some type of load flexibility program. Managed charging could, at a minimum, contribute an additional 50 MW of flexible capacity by 2030 through the enhanced TOU rate enrollment alone.[53]

Most of Colorado's current DR program participation comes from Colorado's largest utility, Xcel Energy (Hledik et al. 2022). The following program examples from Xcel illustrate the range of options utilities have at their disposal to mitigate load growth through transportation-oriented DR initiatives.

Residential charging programs

Xcel Energy has developed a suite of residential demand-side management and electric vehicle charging programs designed to optimize grid performance, reduce peak load, and support customer adoption of clean energy technologies. The follow case study examines three key programs, Charging Perks, Optimize Your Charging, and EV Accelerate at Home, highlighting the utility's comprehensive approach to helping EV owners manage charging to align with both their needs and those of the grid.

Charging Perks

The Charging Perks managed charging program provides incentives for eligible electric and plug-in hybrid vehicle owners that own at-home level 2 chargers.[54] Participants receive a $50 bill credit for enrolling and a $150 annual participation reward for remaining active in the program. The program is structured around dynamic managed charging, using smart charging providers like WeaveGrid to schedule charging sessions based on real-time grid demand, renewable energy availability, and customer preferences. Customers retain the ability to override or opt out of scheduled charging at any time, ensuring participation remains voluntary and prioritizes customer needs. During emergency grid events, charging may be temporarily paused, with advance notice and opt-out options minimizing disruption for customers (WeaveGrid n.d.).

By shifting charging away from peak periods and toward times of surplus renewable generation, Charging Perks actively reduces system stress, supports renewable integration, and enables Xcel to respond quickly to grid needs without requiring costly infrastructure upgrades. The program's requirement for data sharing also provides valuable insights for ongoing grid management and program evaluation.

Optimize Your Charge

The Optimize Your Charge program complements Xcel's dynamic Charging Perks offering by providing a simpler, behavioral alternative.[55] Unlike Charging Perks, which actively schedules and adjusts charging in real time based on grid conditions, Optimize Your Charge does not

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[53] Similarly, managed charging was identified as the largest flexible load resource in New York's "Grid of the Future" proceeding.

[54] Level 2 equipment offers higher-rate AC charging than level 1 technology through 240V (in residential applications) or 208V (in commercial applications) electrical service, and is common for home, workplace, and public charging. Level 2 chargers can charge a BEV to 80% from empty in 4–10 hours (DOT 2025).

[55] The Optimize Your Charge program is available in Xcel's Minnesota, Colorado, and New Mexico service territories.

control charging directly and is not tied to a TOU or discounted rate. Instead, participants receive annual bill credits—$50 in Minnesota and Colorado, and $35 in New Mexico—for charging during selected off-peak hours at least 25% (MN) or 80% (CO and NM) of the time. Customers choose their preferred charging windows and may override them at any time (Xcel Energy n.d.b). By incentivizing scheduled off-peak charging, Optimize Your Charge helps flatten demand curves, reduce grid congestion, and align EV charging with periods of lower wholesale electricity prices. As of April 2024, the program had 5,000 participants across the states where this offering is available (Recharge America 2024).

EV Accelerate at Home

In Minnesota, Colorado, Wisconsin, and New Mexico, the EV Accelerate at Home program offers an additional flexibility option that increases consumer access to charging infrastructure. The program serves as a turnkey solution where Xcel provides, installs, and maintains a level 2 home charger that customers can rent for a monthly fee. Xcel also offers customers the option to enroll their own charger.

The program includes automatic enrollment in a TOU rate (as low as 3.8¢/kWh for overnight charging in Minnesota) and can cover up to 100% of the project cost through custom rebates, making it a strong option for EV owners who do not yet have home charging solutions (Xcel Energy n.d.a). Customers are encouraged to charge during specified overnight hours to benefit from the lowest rates. Still, the program's main value is in simplifying home charging setup and providing a bundled service. This structure not only reduces barriers to EV adoption but also encourages most charging to occur during periods of low grid demand, directly supporting DSM goals.

Commercial charging programs

In addition to these residential offerings, Xcel Energy has established a robust portfolio of commercial charging programs and incentives to accelerate fleet electrification and support broader commercial and community charging needs across its service territories. Recognizing that up-front infrastructure costs are a significant barrier for fleets, workplaces, multifamily properties, and public charging sites, Xcel offers a layered system of rebates and advisory services designed to make the transition to electric vehicles and implement demand-side management cost-effective for businesses.

Commercial EV critical peak pricing

This rate structure incentivizes fleet operators to shift charging to off-peak hours, offering deeply discounted rates as low as $0.00693/kWh during winter off-peak periods, while pricing events during peak grid hours higher to manage grid demand (Xcel Energy 2022). Customers also receive digital tools for near real-time energy monitoring at no additional cost, providing greater visibility and control over charging patterns.

Large C&I load flexibility

Case study – ConnectedSolutions demand response program

The ConnectedSolutions initiative is a standout example of a pay-for-performance load flexibility program tailored for C&I customers in Massachusetts. Utilities including National Grid, Eversource, Cape Light Compact, and Unitil offer this program to help businesses actively reduce their electricity consumption during times of peak grid demand. In return, participating organizations receive direct financial incentives, while the region benefits from improved grid stability, lower system costs, and progress toward clean energy targets (MassSave 2023).

Program structure and participation

Launched statewide in 2019, ConnectedSolutions offers C&I customers two main participation options: Targeted Dispatch and Daily Dispatch (see table D5). To participate, businesses must use behind-the-meter assets that are already installed and operational—such as battery storage or thermal storage systems—at the site where demand reduction will occur. Only behind-the-meter assets that are already installed and operational, such as battery storage or thermal storage systems, are eligible.

Table D5. Summary of Targeted Dispatch and Daily Dispatch options offered by Massachusetts utilities through the ConnectedSolutions initiative

	Targeted Dispatch	Daily Dispatch
Description	Designed for businesses that prefer fewer interruptions. It calls for participation in up to eight “events” per summer when energy use reduction is needed during periods of peak demand, each lasting about three hours, with events usually occurring during weekday afternoons.	For those able to respond more frequently. It involves 30 to 60 events per summer, each 2–3 hours long, also during the same peak demand events. The incentive is higher but requires a five-year commitment.
Events per summer	1–8	30–60
Event duration	3 hours	2–3 hours
Incentive	$45/kW per summer	$200/kW per summer
Incentive lock	None	Five years
Event timing	2–7 p.m.	2–7 p.m.
Notification	Day-ahead	Day-ahead
Eligible days	Monday–Friday, bonus incentive on weekends	Any day of the week

The program is technology neutral. C&I customers can use any method suited to their facility for reducing demand during events as long as they have sufficient metering technology to verify performance. Most organizations join the program through Curtailment Service Providers (CSPs), who help manage participation and maximize performance, though direct enrollment with the utility is also possible.

Verified results and program growth

Independent reviews have documented the program's rapid expansion and effectiveness:

- By the close of 2020, ConnectedSolutions had enrolled approximately 34,000 customers, with a combined reduction capacity of 310 MW—far surpassing the state's 2020 Clean Peak Energy Standard goal of 100 MW and nearly meeting the three-year plan target of 337 MW for peak demand reduction.
- The majority of this capacity—286 MW—came from C&I battery storage, highlighting strong adoption of advanced energy storage solutions.
- Early pilot phases saw C&I participation scale up quickly, growing from roughly 21 MW (99 sites) to nearly 78 MW (276 sites) within a single year.
- While residential participants also contributed through the ConnectedSolutions residential program offering, with an average of 250 kW reduced per event in National Grid's territory during the 2019 summer season, the bulk of the program's impact comes from large C&I participants (Woods et al. 2021)
- In 2023, National Grid Massachusetts reported 40 MW of summer peak demand reduction through the ConnectedSolutions program (Woods et al. 2021) and Eversource reported 30 MW (Eversource Energy 2024).

Program benefits and broader impacts

- **Economic and operational value:** Participating businesses have realized energy cost savings and improved operational resilience, while the program has helped Massachusetts advance its goals for energy storage deployment and peak demand management.
- **Clean grid services:** By aggregating demand reductions and distributed storage, ConnectedSolutions delivers reliable grid support traditionally provided by fossil-fueled peaker plants, but without the associated emissions or pollution.
- **Scalable, verified success:** The program's independently verified results demonstrate its effectiveness and scalability, making it a model for integrating clean energy and flexible demand into the power system. Overall, ConnectedSolutions has established itself as a leading load flexibility program, combining measurable grid benefits, strong customer engagement, and a clear pathway for integrating clean energy solutions into the region's electricity system.

Industrial load flexibility potential

Industrial loads participating in DR programs typically include a range of flexible and energy-intensive systems. Common examples are process loads such as cement mills and aluminum smelting plants, which can significantly reduce energy and power consumption during peak periods. HVAC systems, water and wastewater treatment facilities, refrigeration and cold storage, and compressed air systems are other key candidates due to their controllability and the potential to schedule when they need to utilize energy. Additionally, industrial-scale energy storage systems are increasingly used to shift load and provide grid support during DR events. Lighting and other nonessential loads may also be curtailed, though they generally offer smaller savings. Many industrial participants use automated demand response (auto-DR) technologies to streamline load shedding and improve responsiveness to utility signals. These strategies help facilities reduce costs while supporting grid reliability (Nandy et al. 2022)

Electrification is set to expand this opportunity. As industries decarbonize and shift from fossil-fuel systems to electric boilers, industrial heat pumps, and other electrified processes, their electricity demand will rise substantially. Unlike fossil-fuel systems, these electrified loads can often be adjusted or shifted, making them highly suitable for DR participation. This means that as electrification accelerates, industrial demand response will become even more critical to managing peak demand, integrating variable renewable energy, and maintaining grid reliability.

Total flexible DER capacity in the commercial and industrial sectors reached nearly 78 GW in 2022 and is projected to grow at a compound annual growth rate of 14.7% to 268.4 GW by 2031. Within this broader landscape, industrial customers currently account for nearly half (14.9 GW) of the total potential peak demand savings from U.S. retail DR programs, underscoring their central role in grid flexibility. Capturing this potential will require utilities and policymakers to expand DR offerings tailored to industrial needs, scale up auto-DR adoption, and align program design with electrification and decarbonization pathways to maximize participation and grid value.

Electric Power Research Institute DCFlex initiative

The EPRI DCFlex initiative, launched in 2024, is a three-year project focused on demonstrating how data centers can provide load flexibility to support the electric grid. It involves a collaboration between technology companies like Google, Meta, NVIDIA, and Microsoft; data center operators and developers; utilities including Duke Energy, PG&E, and Portland General Electric; grid operators; and equipment suppliers. The initiative addresses the challenge posed by rapidly increasing electricity demand from AI-driven data centers, which EPRI projects will consume up to 9% of U.S. electricity by 2030.

DCFlex aims to develop and test strategies to enable data centers to reduce or shift power use in response to grid needs without disrupting operations. This includes deploying 5 to 10 “flexibility hubs”—real-world demonstration sites where data centers and utilities test operational flexibility, grid integration, and load management strategies. These hubs serve as “living laboratories” to validate technologies and operational practices that can help balance electricity supply and demand, reduce peak load, and integrate more renewable energy.

The initiative is designed to create reference architectures and shared learnings to accelerate the broad adoption of flexible data center operations. It emphasizes innovation in operations, business models, and regulatory frameworks to unlock data centers as active grid resources, rather than passive loads. By collaborating closely with technology providers, utilities, and regulators, DCFlex aims to address reliability challenges and reduce the costs associated with increasing data center electricity demand.

DCFlex also aligns with energy sector goals of decarbonization and system resilience by helping to manage electric system stress during peak periods and periods of renewable generation variability. The initiative plans to run through 2027, providing timely results and tools to integrate data center flexibility into electricity market operations and grid planning.

Virtual power plants (VPPs)

We refer the reader to the *Virtual Power Plant Flipbook*, where the background, key features, and impacts for 16 utility VPP programs are reported (Brehm and Tobin 2024). During the extreme East Coast heat wave described in **Virtual power plants,** CPower Energy provided about 18,500 MWh to meet peak demand across PJM, ISO-NE, and NYISO (CPower Energy 2025).

Repowering California

Repowering California is an innovative initiative designed to enable private companies to fund demand flexibility projects and receive certified capacity credits, which can be used to support new or expanded loads without increasing net grid impact. The program introduces a model where large load customers can enter into power purchase agreements for VPPs, allowing them to directly procure demand reductions from DERs like batteries, EV charging, and energy efficiency projects. These resources are compensated for reducing demand during critical peak hours. The program builds on California's Market Access Programs, which certify and credit energy savings, ensuring that capacity reductions are real and not double-counted. This model introduces revenue streams that help electricity consumers finance previously unviable projects while simultaneously incentivizing large load customers to invest in demand-side solutions (WattCarbon 2025).

Illinois Clean and Reliable Grid Affordability (CRGA) Act

CRGA (Senate Bill 25) allows owners of distributed storage to apply for rebates if they participate in a scheduled dispatch VPP program for five years. The VPP program will aggregate distributed resources, including batteries from rooftop and community solar, and provide compensation for scheduled dispatch (CRGA Act 2025). CGRA was passed by the Illinois General Assembly in late October 2025; Governor J.B. Pritzker signed it in January 2026.

Voltus Bring Your Own Capacity (BYOC) Program

Voltus has partnered with Cloverleaf Infrastructure to introduce a BYOC framework for data centers. Instead of selling flexible capacity into traditional power markets, Voltus contracts directly with hyperscalers to finance and harness local community flexibility. This innovative structure helps data centers accelerate VPP development in diverse regions and sidesteps market-based barriers by enabling direct negotiations between resource aggregators and end users. The BYO approach leverages hyperscalers' financial strength and urgent demand, stimulating new VPP projects (Allsup 2025)

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