Grid Growth, Utilization, and Affordability: A Playbook for States

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Executive Summary

The United States electrical grid has entered a period of rapid transformation. Electricity demand is surging at a pace not seen in 25 years, driven by data centers, industrial reshoring, and rising electrification.[1] In parallel, electricity bills have become a major economic and political concern. Retail rates increased roughly ~25% from 2018 to 2024, driven by increasing transmission and distribution costs, and are projected to rise faster than inflation through 2030 absent intervention.[2] If states respond to load growth using the planning models of the past (peak-driven buildout of poles / wires), retail customers will bear an undue cost burden. If modern tools are used, states can increase utilization of existing grid assets to defer near-term costs while harnessing long-term load growth to spread fixed costs over a growing customer base. Together, these actions would stabilize electricity prices and help preserve customer affordability. State leaders will play a critical role in determining the path forward. Proactive leaders will take steps to more intelligently utilize existing infrastructure while securing decade-defining long-term investments in their regional economy.

The Utilization Challenge*:* Electricity rates have outpaced inflation since 2022, driven by factors that predate the recent surge in demand.[3] Persistent underinvestment in *transmission* and *distribution* (poles and wires) has burdened the electricity system with staggering costs to maintain aging, vulnerable infrastructure networks. In addition, the incentive to lean on capital-intensive, new investments - which earn utilities a guaranteed rate of return - embeds additional costs borne by ratepayers.[4]

The United States' power system plans infrastructure to accommodate the highest demand hours of the year (peak utilization) and rewards utilities for breaking ground on new projects to serve this signal (rather than optimizing assets that have already been paid for). In addition, most state regulators and utilities lack consistent, transparent metrics to understand the percentage of underutilized capacity on the transmission and distribution grid. As a result, customers finance infrastructure that is underutilized most of the year (~50 - 55% average annual network utilization).[5]

If this peak-driven planning model does not change, grid utilization is likely to remain unchanged and rapid electricity demand growth could significantly increase infrastructure costs for all ratepayers. However, emerging evidence suggests that a combination of market reforms and technology deployment would allow states to significantly increase grid utilization, adding substantial loads without increasing system peaks and freeing up ~75 - 100GW of system headroom without capacity expansion.[6]

A Roadmap for States: To stabilize rates, state leaders must pivot their regional electricity system to reward technology deployment, drive higher utilization of existing assets, and increase speed-to-power without cross-subsidizing large, commercial loads.

Near-term (2026 - 2030): Before the end of this decade, states should focus on delivering maximum value from grid infrastructure customers have already paid for, while using new,

[1] T. H. Norris, T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell, 2025, "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems." NI R 25-01. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University, https://nicholasinstitute.duke.edu/publications/rethinking-load-growth; Jennifer Downing, Nicholas Johnson, Mailinh McNicholas, Rima Oueid, Joseph Paladino, and Elizabeth Belles Wolf e. 2023, "Review of Pathways to Commercial Liftoff: Virtual Power Plants," *U.S. Department of Energy (DOE)*, archived October 1, 2023, at https://web.archive.org/web/20231001035607/https://liftoff.energy.gov/wp-content/uploads/2023/09/20230911-Pathways-to-Commercial-Liftoff-Virtual-Power-Plants_update.pdf.
[2] Comstock, Owen, "U.S. Electricity Prices Continue Steady Increase." *U.S. Energy Information Administration (EIA)*, May 2025. https://www.eia.gov/todayinenergy/detail.php?id=65284.
[3] Comstock, "U.S. Electricity Prices Continue Steady Increase."
[4] Utilities earn a ~9 - 11% return on capital projects while fuel costs, operations, and maintenance are passed through directly to the consumer at no mark-up / profit
[5] Norris et al. "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems."
[6] Downing et al. "Pathways to Commercial Liftoff: Virtual Power Plants."

large loads as a catalyst for accelerated technology adoption and improved interconnection processes.

- *Scale Virtual Power Plants (VPPs):* Virtual power plants (VPPs) - aggregations of distributed energy resources (DERs) including batteries, smart thermostats, and electric vehicles - can provide grid reliability at ~40 - 60% lower cost to traditional alternatives[7] and be deployed in months, not years.[8] The U.S. Department of Energy estimates that scaling VPPs 3 - 5x by 2030 (to ~80 - 160 GW) could serve ~10 - 20% of peak load and save power systems $10 billion annually in grid costs.[9] States looking to rapidly expand their VPP portfolio should default to auto-enrollment of enabled devices, reward utilities that grow their VPP footprint, and set standards that allow for device interoperability. Passed in 2020, the Federal Energy Regulatory Commission's (FERC) Order 2222 will also help to accelerate VPP adoption by ensuring DERs can aggregate heterogeneous technologies with lower participation barriers (allowing aggregations down to 100 kW). In addition, Order 2222 will provide a national regulatory foundation for VPPs to compete directly with traditional generation assets. California's Independent System Operator (CAISO) currently operates the largest VPP system nationally with 515 megawatts (MW) of enrolled capacity and offers a playbook for states scaling VPPs in their own regional grids while programs in Texas are aiming for 1GW of VPPs by 2035.[10]
- *Increase grid utilization to make better use of existing infrastructure:* Building new transmission and distribution (T&D) infrastructure is the largest driver of cost increases to ratepayers. Recent evidence suggests that by better utilizing existing T&D assets, state regulators and utilities can defer or right-size new grid investments, reducing unnecessary capital spending and lowering long-term costs. Even modest improvements in utilization, such as identifying underutilized capacity or targeting overloaded circuits at times of peak demand, can produce significant affordability benefits when scaled across the distribution grid. Several states are already leading on this front. For example, legislation passed by the Virginia House of Delegates on a unanimous, bipartisan basis and passed the Virginia Senate in February 2026 (HB 434/SB 621) would give the Virginia State Corporation Commission more tools to evaluate grid utilization metrics, ensuring ratepayers are getting full value from infrastructure they are already paying for.[11]
- *Prioritize large load flexibility:* States should establish flexible / interruptible service classes for large loads and allow sophisticated customers to 'Bring Your Own Capacity' (BYOC). Under BYOC, a customer procures a combination of generation, storage, and VPP participation to cover their incremental reliability needs (avoids contributing to annual peaks) in exchange for faster interconnect - improving overall system level utilization and protecting ratepayers from financing peak-driven upgrades. Texas has seen impressive results with its 'Connect and Manage' system, an approach where large loads accept fast grid interconnection in exchange for possible curtailment during times of peak stress. Within the Electric Reliability Council of Texas (ERCOT)

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[7] Alternatives to serve peak load are most often natural gas peaker plants or utility-scale battery systems.
[8] Ryan Hledik and Kate Peters, "Real Reliability: The Value of Virtual Power," *Brattle*, May 2023, https://www.brattle.com/insights-events/publications/real-reliability-the-value-of-virtual-power/.
[9] Downing et al., "Pathways to Commercial Liftoff: Virtual Power Plants."
[10] "California's Demand Side Grid Support Program Grows to 500 Megawatts of Capacity." *California Energy Commission (CEC)*, October 2024, https://www.energy.ca.gov/news/2024-10/californias-demand-side-grid-support-program-grows-500-megawatts-capacity; Brian Martucci, "NRG, Renew Home Aim for 1-GW Texas VPP by 2035," *Utility Dive*, November 12, 2024, https://www.utilitydive.com/news/nrg-renew-home-aim-for-1-gw-texas-vpp-by-2035/732662/.
[11] *See* House Bill 434, which would establish grid utilization metrics for Phase I and Phase II utilities in the Commonwealth of Virginia. https://www.governor.virginia.gov/newsroom/news-releases/2026/february-/name-1112416-en.html.

territory, large loads (10 MW or larger) can interconnect in ~18 - 30 months and small loads (below 10 MW) in ~8 to 12 months.[12] In contrast, congested regions like the mid-Atlantic grid (Pennsylvania-New Jersey-Maryland Interconnection, PJM) have seen average wait times of 8 years for interconnect.[13]

- *Modernize rate design and contract structures to protect customers:* States can isolate large loads within distinct rate classes to protect smaller customers.[14] Grids may pursue a combination of default time-of-use pricing, stronger on-peak/off-peak differentials, and specialized large-load tariffs which can reward load shifting, reduce coincident peaks, and ensure that new demand pays its fair share of system costs. States may also encourage large loads to pay for critical grid upgrades, agree to minimum contract lengths, or sign 'take or pay' contracts to reduce the risk of overbuild in response to new demand signals.[15,16]
- *Pursue permitting reform:* Faster permitting would expand generation, transmission, and distribution capacity across the grid. States can take steps to fast-track permitting through statutory 'shot clocks' that mandate permit decisions with fixed periods (e.g., ~12 months for municipal reviews, 15 months for state-level listing). States can also streamline processes by establishing centralized siting authorities that would offer a single, consolidated application process to replace fragmented local approvals. Additionally, states can designate pre-cleared 'Energy Opportunity Zones' in areas with low environmental impact, allowing developers to utilize categorical exclusions and programmatic environmental reviews to by-pass years of site-specific litigation.

Medium-term (2030 - 2035): In addition to the steps above, states should begin to take action on initiatives that will benefit regional grids in the early 2030s, including accelerating the deployment of grid-enhancing technologies and expanding clean, firm capacity.

- *Deploy grid-enhancing technologies (GETs):* Grid-enhancing technologies are "commercially available but underutilized" technologies including advanced conductors, power-flow controls, and dynamic line rating (DLR).[17] Studies have shown that reconductoring can increase capacity by more than 100% while DLR systems can increase line capacity as much as 70%.[18] Deploying GETS in capacity-constrained regions can serve as a high-speed, low-cost alternative to building new transmission lines with many solutions that can be deployed in months rather than years.
- *Deliver incremental generation:* Where available, states should encourage new loads to unlock existing firm, low-carbon generation from uprates and restarts of hydropower and nuclear facilities. Uprates have been the primary driver of new US nuclear capacity for decades, with roughly ~8GW of uprates approved to date across the US nuclear fleet.[19] Uprates can take a few years to plan and execute, in part because plants may need to wait until their refueling cycle for more extensive changes to system

[12] Jenifer Fernandes, "ERCOT Interconnection Process: Generation Entity Winter Weather Preparedness Workshop," *Electric Reliability Council of Texas (ERCOT)*, October 28, 2024, https://www.ercot.com/files/docs/2024/10/30/0940-AM-ERCOT-Interconnection-Process-Generation-Entity-Winter-Weather-Preparedness-Fernandes.pdf.

[13] Abigail Weeks et al., "PJM's Speed to Power Problem and How to Fix It," *Rocky Mountain Institute (RMI)*, November 4, 2025, https://rmi.org/pjms-speed-to-power-problem-and-how-to-fix-it.

[14] Alyssa Perez, Sarah Wang, and Lauren Shwisberg, "Large Energy Users Want Power. Here's How to Protect Other Ratepayers from the Costs," *RMI*, November 7, 2025, https://rmi.org/large-energy-users-want-power-heres-how-to-protect-other-ratepayers-from-the-costs/.

[15] Isabelle Riu, Kushal Patel, Liz Mettetal Morgan Santoni-Colvin, et al., "Tailored for Scale: Designing Electric Rates and Tariffs for Large Loads," *Energy and Environmental Economics, Inc. (E3)*, December 2025, https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf.

[16] Perez et al., ""Large Energy Users Want Power. Here's How to Protect Other Ratepayers from the Costs."

[17] White et al., "Pathways to Commercial Liftoff: Innovative Grid Deployment," *DOE,* April 2024, https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf

[18] Chojkiewic et al., "2035 and Beyond Report: Reconductoring," *GridLab and UC Berkeley Goldman School of Public Policy*, n.d., https://www.2035report.com/wp-content/uploads/2024/04/GridLab_2035-Reconductoring-Technical-Report.pdf.

[19] "Planning a Reactor Power Uprate Time to Get in Line at the NRC," *Morgan Lewis*, February 20, 2025, https://www.morganlewis.com/blogs/upandatom/2025/02/planning-a-reactor-power-uprate-time-to-get-in-line-at-the-nrc.

configurations (e.g., changes to turbines, pumps, or transformers), meaning states looking to see additional capacity from existing nuclear resources in the early 2030s should begin planning for uprates today.

Long-term (2035+): Finally, states should begin laying the groundwork for policy proposals that will speed the construction of clean, firm generation, hasten interconnect, and re-align utility incentives to reward technology adoption and asset utilization for the long-term.

- *Build the fleet of the future:* States will need to scale low-carbon, firm assets including next generation geothermal, utility-scale renewables with battery storage, nuclear (Gen III and Gen IV designs), and carbon capture and utilization systems to meet the electricity needs of the future. The work to originate, fund, and develop these projects has already begun, with hundreds of megawatts of demonstration projects breaking ground across the country. States should take steps to attract the local infrastructure development and high-quality trades jobs that these projects provide. For example, states can ensure that local incentives stack with federal subsidies, siting and permitting processes are streamlined, and state regulations send clear market signals that businesses can plan decades-long infrastructure investments within their jurisdictions.
- *Reform planning and utility incentives:* Finally, states should take steps to better align utility incentives with policy objectives beyond capital spending - including asset utilization, technology adoption, and low-carbon performance.

The United States has repeatedly modernized its energy system to support economic growth - from rural electrification beginning in the 1930s to the shale boom of the 2010s. Today's challenges call for states to take aggressive steps to deploy proven technologies (VPPs, DERs) while shifting incentives to reward cost-efficient infrastructure expansion. States that act quickly to increase grid utilization, prioritize flexibility, and realign incentives to reward technology deployment can accommodate load growth while protecting retail customers from rising bills.

Time Horizon	Solution	Description	Potential Impact	Real-World Examples
Short-term (2026–2030)	**Scale Virtual Power Plants (VPPs)**	Aggregate distributed energy resources - DERS: EVs, batteries, thermostats - to provide capacity, peak shaving, and reliability services at lower cost than new generation or wires	• 80–160 GW of VPPs nationally by 2030 (3x current scale) could address 10 - 20% of peak demand[20] • 40–60% lower net cost than gas peakers or utility-scale storage[21]	• California (DSGS, ~500 MW) • Hawaii (BYOD+) • Colorado (SB 218) • Maryland (HB 1256) • Minnesota (Xcel DER portfolio, ~200MW)
	Increase grid utilization	Empower state regulators to measure grid utilization, and incentivize utilities to achieve higher levels of utilization through energy storage resources, customer-owned capacity, VPPs, and more	• Under the broad umbrella of increasing grid utilization, the US DOE found that proactive utility planning, tariff structures, and vehicle-grid integration could reduce grid infrastructure investments by as much as 30%[22]	• Virginia (HB 434) mandates utilities to align on grid utilization metrics and report annually • Illinois (SB 25) includes provisions to mandate 3GW of energy storage and encourage VPP integration to increase utilization of existing infrastructure • California (DIDF) has a regulatory process designed to identify non-wires alternatives to solve grid capacity needs
	Prioritize large load flexibility	Allow large loads including data centers & industrial facilities to connect faster by covering their own capacity needs and accepting limited curtailment	• 3-5 years faster interconnection[23] • Avoids ~270 MW of new capacity per GW of load, eliminating ~$80 million in incremental system costs per GW of large load[24] • ~76GW of new load (10% of national peak demand) could be integrated with average annual curtailment of ~0.25%[25]	• ERCOT (Connect and Manage) • Arizona data center flexibility pilot (Salt River Project)
	Modernize rate design / contract structures	Default to time-of-use pricing, strong on/off peak differentials, and large-load tariffs to ensure new demand minimizes its coincident peaks and pays for its fair share of system costs	• Customers enrolled in a TOU pilot in California facilitated ~14% average peak reduction and ~8% average bill reduction[26]	• PSEG has implemented 'time of day' pricing to all of its customers (PSEG 2025) • 60+ large-load tariffs have been implemented or are currently being piloted nationally (DELTa database)
Medium-term (2030–2035)	**Deploy Grid-Enhancing Technologies (GETs)**	Increase capacity of existing transmission system via reconductoring, dynamic line rating (DLR), power-flow controls	• Up to 100%+ capacity increase via reconductoring[27] • Dynamic line rating investments payback in 0 - 2 years[28] • In congested regions like PJM, GETs could enable 6.6GW of new projects to interconnect before 2030[29]	• MISO (Reconductoring overloaded lines to ensure only 88% of loaded rating) • CAISO (GETs projects)
	Deliver incremental, firm generation (Uprates & Restarts)	Unlock low-cost, low-carbon, firm capacity from existing hydro and nuclear assets	• 8.5 GWe nuclear reactor uprates have been submitted for NRC-Licensed, Operating nuclear reactors through 2032[30] • Significantly lower LCOE, compared to new generation capacity[31]	• Nuclear uprates (~100MW+ uprates fleet-wide across major nuclear operators) • Nuclear restarts and life extensions (Crane, Diablo Canyon, Palisades)
Long-term (2035+)	**Build the fleet of the future**	Scale low-carbon, firm assets including geothermal, nuclear (Gen III/IV), CCS-equipped gas, long-duration storage	• Including next generation, firm technologies can decrease the total system cost of decarbonization. For example, generation and transmission costs may fall by as much as ~37% with scaled deployment of additional nuclear tech[32]	• Nuclear pilots (Select examples- TVA, Western Interconnect, Dow / Amazon supporting SMRs) • Geothermal pilots (Select examples - Nevada, New Mexico)
	Reform planning, utility incentives	Shift utility earnings from capex deployment to outcomes (affordability, utilization, speed)	• Aligns utility behavior with ratepayer outcomes • Reduces bias toward over-building	• Utility incentive reforms (Colorado, New York, Hawaii)

[20] Downing et al., "Pathways to Commercial Liftoff: Virtual Power Plants."
[21] Ryan Hledik and Kate Peters, "Virtual Power Plants (VPPs) Could Save US Utilities $15-$35 Billion in Capacity Investment over 10 Years," *Brattle, for Google*, May 2, 2023, https://www.brattle.com/insights-events/publications/real-reliability-the-value-of-virtual-power/.
[22] "Multi-State Transportation Electrification Impact Study." *DOE*, March 2024, https://www.energy.gov/sites/default/files/2024-03/2024.03.18%20NREL%20LBNL%20Kevala%20DOE%20Multi-State%20Transportation%20Electrification%20Impact%20Study%20FINAL%20DOCKET.pdf.
[23] Carlo Brancucci, Dylan Cutler, and Jesse Jenkins, "Flexible Data Centers: A Faster, More Affordable Path to Power," *Camus, encoord, and Princeton ZERO Lab*, December 2025. https://www.camus.energy/flexible-data-center-report.
[24] Branucci et al., "Flexible Data Centers: A Faster, More Affordable Path to Power."
[25] Norris et al., "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems."
[26] Ahmad Faruqui and Ziyi Tang, "Time-Varying Rates Are Moving from the Periphery to the Mainstream of Electricity Pricing for Residential Customers in the United States," *Brattle* 2023. https://www.brattle.com/wp-content/uploads/2023/07/Time-Varying-Rates-are-Moving-from-the-Periphery-to-the-Mainstream-of-Electricity-Pricing-for-Residential-Customers-in-the-United-States.pdf.
[27] Chojkiewic Emilia et al., "2035 and beyond Report: Reconductoring," *DOE*, December 2020, p. 9, https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf
[28] "Grid Enhancing Technologies: A Case Study on Ratepayer Impacts," *DOE*, February 2022, https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf.
[29] "GETting Interconnected in PJM," *RMI*, February 15, 2024, https://rmi.org/insight/analyzing-gets-as-a-tool-for-increasing-interconnection-throughput-from-pjms-queue/.
[30] "Power Uprates," *Nuclear Regulatory Commission*, n.d., https://www.nrc.gov/reactors/operating/licensing/power-uprates.
[31] "Lazard Releases 2025 Levelized Cost of Energy+ Report," *Lazard*,June 16, 2025. https://www.lazard.com/news-announcements/lazard-releases-2025-levelized-cost-of-energyplus-report-pr/.
[32] "Advanced Nuclear Pathways to Commercial Liftoff - Report Update Summary Presentation," *DOE*, September 2024.

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Overview

The United States' electrical grid is frequently described as the "largest machine in the world."[33] It includes a web of over 12,500 utility-scale power plants and 6 million miles of transmission and distribution lines, all synchronized to the same frequency.[34] For decades, this machine operated in a predictable environment - electricity demand was flat, reserve margins were comfortable, and the primary challenge was gradual decarbonization of the generation fleet.[35]

The grid has now entered a period of rapid transformation, carrying profound impacts for economic growth, national security, and regional politics.[36] States face a trilemma of challenges: managing explosive load growth, ensuring ratepayer affordability, and modernizing / decarbonizing the generation fleet. Navigating these hurdles will require a combination of regulatory reform, market innovation, and technology adoption - changes could save as much as ~$15 - 35B in grid upgrade costs through 2035 and halve interconnection timelines.[37]

This report acts as a guidebook for states navigating grid expansion, infrastructure modernization, and customer affordability. First, it explains the structure of the US grid (Part I). Next, it examines pressures on ratepayers and the role load growth can play in driving systemic change (Part II). Then, the report examines current barriers to affordable grid modernization and expansion (Part III). Finally, it proposes solutions that states can adopt today and in the near-future to build a grid that drives economic growth without placing undue cost burdens on households and businesses (Part IV).

The United States has transformed its energy system through technology many times before - including rural electrification in the 1930s, the rapid deployment of nuclear power in the 1970s, and the shale gas revolution of the 2010s. Now is the time to unleash American electrotech to deliver energy security, affordability, and economic growth at scale.

Part I: Grid 101

To govern the grid, one must first understand how it is physically connected and financially regulated.

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[33] Jim Follum, "How Measurements Are Modernizing the Electric Grid," *Pacific Northwest Reagional Laboratory*, November 2021, ttps://www.pnnl.gov/events/keeping-eye-worlds-largest-machine-how-measurements-are-modernizing-electric-grid.

[34] "How Many Power Plants Are There in the United States?," *U.S. Energy Information Administration*, October 2023, https://www.eia.gov/tools/faqs/faq.php?id=65&t=2; "U.S. Department of Energy Announces $34 Million to Improve the Reliability, Resiliency, and Security of America's Power Grid," *Advanced Research Projects Agency-Energy,* January 2024, https://arpa-e.energy.gov/news-and-events/news-and-insights/us-department-energy-announces-34-million-improve-reliability-resiliency-and-security-americas-power-grid.

[35] John D. Wilson and Zach Zimmerman, "The Era of Flat Power Demand is Over," *Grid Strategies*, December 2023, https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

[36] Josh Saul and Mark Chediak, "Election Shocks Underscore Power Bills as New Political Risk," *Bloomberg*, November 6, 2025, https://www.bloomberg.com/news/articles/2025-11-06/election-shocks-underscore-power-bills-as-new-political-risk.

[37] "Electricity Affordability Toolkit: Virtual Power Plants," *RMI*, September, 2025, https://affordability-toolkit.rmi.org/pdfs/virtual-power-plants.pdf; Brancucci et al., "Flexible Data Centers: A Faster, More Affordable Path to Power."

The Physical Grid: The grid is composed of three distinct stages, each with its own primary regulator:

Stage	Description	Primary Regulator
Generation	Process of creating electricity in large power plants (nuclear, thermal - gas / coal, renewables - wind, solar, hydroelectric, etc.)	Federal Energy Regulatory Commission (FERC) - Wholesale; States (Siting)
Transmission	Moving electricity long distances via high-voltage 'interstate highways'	FERC, Regional Transmission Operators (RTOs)
Distribution	Delivering power to the end customer over lower-voltage, local power lines	State Public Utility Commissions (PUCs)

The Financial Grid: Financial management of grid assets depends entirely on a state's market model and helps explain why customers in neighboring regions may see different pricing or incentive structures for similar infrastructure.

Utility Model	Description	Core regions
Vertically Integrated	A single utility operates the entire value chain (generation, transmission, distribution) and provides a bundled service to customers. Rates are set by a state's Public Utility Commission (PUC) based on the utility's cost of service.	Southeast Southwest, Mountain West, Pacific Northwest
Deregulated	Utilities are primarily 'wires' companies that operate transmission and distribution networks, but are largely divested from their generation assets. In deregulated markets, generation is instead dominated by Independent Power Producers (IPPs) who own power plants and compete in a wholesale market run by a non-profit Independent System Operator (ISO) or Regional Transmission Organization (RTO). ISOs / RTOs dispatch the lowest-cost power plants first, driving down the price of electricity generation through competition.	Northeast: PJM[38], NYISO, ISO-NE Midwest: MISO Texas: ERCOT California: CAISO

In deregulated markets (29 states, two-thirds of electricity demand), non-profit Independent System Operators (ISOs) use complex auctions to ensure the lights stay on.[39] These include:

[38] Note - Many, but not all, utilities in PJM are deregulated including Exelon (PA, NJ, MD), PPL (PA), PSE&G, AEP (OH), and AES (OH). Others remain vertically integrated, including: Dominion Energy (VA), Duke Energy (OH, KT), First Energy (WV).

[39] Kathryne Cleary and Karen Palmer, "US Electricity Markets 101, " *Resources for the Future*, March 3, 2020, https://www.rff.org/publications/explainers/us-electricity-markets-101/.

Auction	Description	Time Horizon
Energy Market *The Price*	The energy market dictates the wholesale price for electricity consumed. Prices are determined by the marginal cost of adding another unit of electricity - i.e., the cost of the power plant needed to meet demand at a specific moment	Day-ahead (95%) Real-time (5%)
Capacity Market *The Insurance Policy*	The capacity market functions like an insurance policy to ensure the grid can maintain long-term reliability. ISOs pay generators not for the energy they produce, but for the *capacity* (MW) they *promise to have available* during peak stress events in the future	1 - 3 years ahead

Capacity markets can send an early warning signal about future grid scarcity. For example, in PJM's recent 2025 - 2026 auction, capacity prices jumped nearly tenfold ($29/MW-day to ~$270/MW-day) - indicating a severe crunch between expected supply and forecasted demand.[40,41]

What's on my bill? Customers in vertically integrated markets are billed differently than those in deregulated markets. In vertically integrated markets, customers typically see a bundled rate and pay one entity for generating electricity, moving it across the state (*transmission*), and delivering it to their home (*distribution*). In deregulated markets, customers often see an 'unbundled bill' - with one section reflecting the cost of electricity supply (competitive *generation*) and the second cost reflecting the cost of maintaining the *transmission* and *distribution* network (utility monopoly).

How do utilities make money? A utility's ownership structure plays an important role in how it makes money, with implications for how it invests in new infrastructure, maintains its existing fleet, and sets customer rates. Utilities are either investor-owned (private shareholders) or publicly-owned (municipalities, co-ops).

Utility Ownership Structure	Owners	Profit Structure	Regulator(s)	Financing	Taxes	Examples
Investor Owned Utility (IOU)	Private shareholders - who own stock in the utility	Profit-seeking, earn a 9 - 11% regulated return on equity	State Public Utility Commissions	Equity raised through shareholders Corporate debt	Federal and state income taxes (collected from ratepayers)	Southern Company Duke Energy PG&E
Publicly Owned Utility (POU)	Community ownership - either via a municipality or member-owners (co-ops)	Non-profits, seek service and cost recovery	Local boards or City Councils	Tax-free municipal bonds	Tax exempt though may make Payments in Lieu of Taxes (PILOT) on properties	Los Angeles Department of Water & Power (LADWP) Tennessee Valley Authority (TVA)

IOUs are the dominant utility model in the United States. Nationally, approximately 200 IOUs serve almost three-quarters of American customers, particularly large cities and suburbs. POUs are

[40] Ashley Lawson, "PJM's Electric Capacity Market: Background and Current Issues," *United States Congress*, 2025, https://www.congress.gov/crs-product/R48553.
[41] Texas (ERCOT) is a notable exception to the energy / capacity market design. ERCOT has no capacity market - instead, generators are paid only for energy produced. To ensure sufficient generation is built, ERCOT allows wholesale energy prices to spike to a cap (formerly ~$9,000/MWh, now ~$5,000/MWh) during times of scarcity. This scarcity pricing is designed to encourage infrastructure investment, but carries extreme volatility risks - as seen during Winter Storm Uri; *See* Edward Klump, "Texas Slaps Down $9,000 Power Prices After Blackout Chaos," *Energy Wire by Politico*, December 3, 2021, https://www.eenews.net/articles/texas-slaps-down-9000-power-prices-after-blackout-chaos/.

prevalent (~2000+) but often smaller - serving lower population density areas (with exceptions including LADWP).

Each utility model presents trade-offs. IOUs earn a guaranteed rate of return (~9 - 11%) on their capital investments, creating financial incentives to build new infrastructure to accommodate load growth - rather than finding new capacity / system flexibility through efficiency measures. In contrast, POUs are non-profits that answer to local voters, and are often politically pressured to keep rates low. POUs have maintained lower prices when compared to IOUs, however, POUs may risk slower capital deployment.

Part II: The Grid Today

The Affordability Crisis

Electricity prices have become a significant budgetary concern for households and a political liability in election cycles across the country.[42] In 2025, rising rates flipped two incumbent seats on Georgia's Public Service Commission while New Jersey's Governor-elect campaigned on a promise to freeze utility rates in the state.[43] Across the United States, conversations on affordability are reshaping the electorate, with nearly half of Americans saying cost of living is 'the worst they can remember'.[44]

Historical trends: Electricity rates have outpaced inflation since 2022, driven by factors that predate today's surge in electricity demand.[45] Retail rates rose ~25% from 2018 - 2024 because of increased spending on *transmission* and *distribution* (T&D, or, poles and wires). In contrast, wholesale *generation* costs have declined nationally, driven by improved thermal fleet efficiency (e.g., coal retirements, lower natural gas prices) and lower renewable energy costs.[46,47] Affordability challenges are expected to intensify in the face of significant load growth, with rates rising an average of ~10 - 15% by 2030 absent technology or policy intervention.[48]

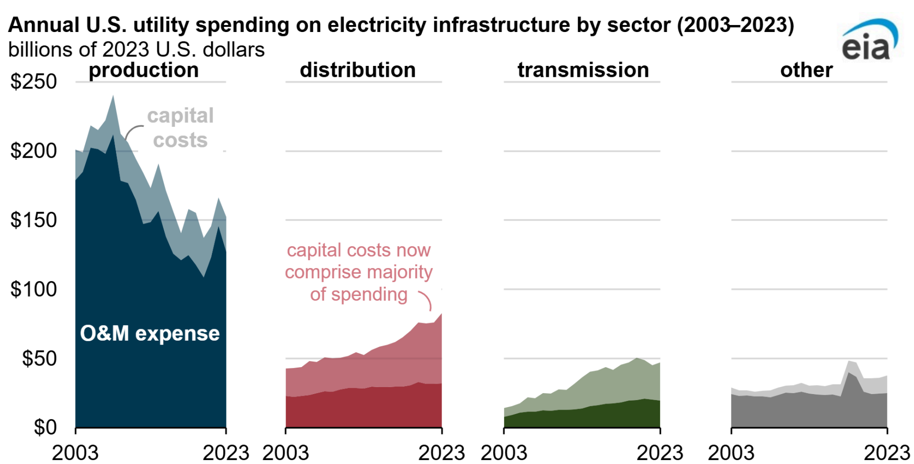

Figure 1: Annual U.S. utility spending on electricity infrastructure by sector (2003 - 2023)

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[42] Brad Plumer, Harry Stevens, and Rebecca F. Elliott, "Why the Price of Electricity Is Spiking around the Country," *The New York Times*, October 30, 2025, https://www.nytimes.com/2025/10/30/climate/electricity-prices.html.
[43] "Georgia Public Service Commission Election, 2025," *Ballotpedia*, November 4, 2024, https://ballotpedia.org/Georgia_Public_Service_Commission_election,_2025; "Promise Kept: Governor Sherrill Takes Bold Action with Executive Orders Declaring State of Emergency on Utility Costs," *Office of the Governor of New Jersey*, January 20, 2026, https://www.nj.gov/governor/news/2026/20260120a.shtml.
[44] Erin Doherty, "Poll: Trump's Own Voters Begin Blaming Him for Affordability Crisis," *Politico*, December 4, 2025, https://www.politico.com/news/2025/12/04/poll-americans-trump-voters-affordability-crisis.
[45] Comstock, "U.S. Electricity Prices Continue Steady Increase."
[46] Ryan Hledik, Long Lam, and Audrey Yan, "Factors Influencing Recent Trends in Retail Electricity Prices in the United States," *Brattle*, October 2025, https://eta-publications.lbl.gov/sites/default/files/2025-10/full_summary_retail_price_trends_drivers.pdf; Lori Aniti, "Grid Infrastructure Investments Drive Increase in Utility Spending over Last Two Decades," *EIA*, 2024, https://www.eia.gov/todayinenergy/detail.php?id=63724.
[47] Downing et al., "Pathways to Commercial Liftoff: Virtual Power Plants."
[48] Comstock, "U.S. Electricity Prices Continue Steady Increase,"; ICF has evaluated residential electricity rates at 4 utilities nationwide, estimating 15% - 40% cost increases by 2030 (compared to 2025 rates). *See* Lalit Batra, Deb Harris, George Katsigiannakis, Justin Mackovyak, Himali Parmar, and Maria Scheller, "Rising Current: America's Growing Electricity Demand," *ICF*, n.d., https://www.icf.com/-/media/files/icf/reports/2025/energy-demand-report-icf-2025_report.pdf?rev=c87f111ab97f481a8fe3d3148a372f7f.

Aniti, Lori. "Grid Infrastructure Investments Drive Increase in Utility Spending over Last Two Decades." *EIA, 2024* https://www.eia.gov/todayinenergy/detail.php?id=63724.

Much of the US electric grid was constructed in the 1960s - 1970s, with infrastructure that struggles to meet modern needs or endure intensifying weather systems.[49] ~50 - 65% of utility capex is now 'defensive' - hardening or replacing aging assets rather than investing in system expansion.[50] Spending on *distribution* networks is a significant cost driver because these 'last mile' wires are highly distributed and vulnerable.[51] In states that have already faced natural disasters, the challenges compound. Utilities and PUCs have struggled to balance reactive, short-term spending to rebuild post-disaster with budgeting for proactive, long-term infrastructure hardening (e.g., undergrounding, substation upgrades). Supply chain constraints have also intensified costs. For example, transformer prices rose 60 - 80% from 2020 - 2024 while lead times doubled, with similar spikes for high-voltage breakers and other critical equipment.[52]

Household impact: Across most regions, residential customers disproportionately bear the brunt of rising rates, reflecting policy choices and underlying cost allocation structures. Since 2019, residential rates have increased 27%[53] compared to 19% for commercial and industrial (C&I) customers.[54] Consequently, nearly 25% of U.S. households were unable to pay at least 1 energy bill in 2023 with low-income communities experiencing 3x the cost burden vs. non-low-income households.[55,56]

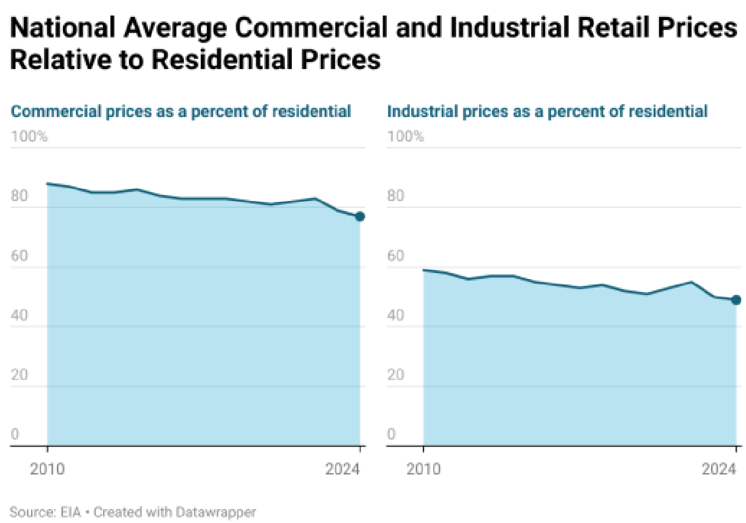

Figure 2: National Average Commercial and Industrial Retail Prices Relative to Residential Prices
Lawrence Berkeley National Lab & The Brattle Group - data via EIA, 2025

Utility models: Affordability outcomes also vary across utility models. While publicly owned utilities (POUs) often move more slowly on major infrastructure expansions, their non-profit mandates,

[49] "What Does It Take to Modernize the U.S. Electric Grid?," *Grid Deployment Office, DOE*, October 19, 2023, https://www.energy.gov/gdo/articles/what-does-it-take-modernize-us-electric-grid.
[50] Hledik et al., "Factors Influencing Recent Trends in Retail Electricity Prices in the United States."
[51] "What Does It Take to Modernize the U.S. Electric Grid?" *Grid Deployment Office, DOE*.
[52] Sagar Chopra and Benjamin Boucher, "Supply Shortages and an Inflexible Market Give Rise to High Power Transformer Lead Times," *Wood Mackenzie*, April 2, 2024, https://www.woodmac.com/news/opinion/supply-shortages-and-an-inflexible-market-give-rise-to-high-power-transformer-lead-times.
[53] 27% rise accounts for average increase in retail electricity prices 2019 - 2024 in nominal terms.
[54] C&I customers often benefit from negotiated contracts and economic development subsidies that keep their electricity rates lower. And, C&I customers have steady load profiles that avoid coincident peaks (i.e., avoid using electricity when prices are highest).
[55] "Crisis in Energy Affordability Summer Shutoff Protections and Bill Support Fail to Adapt to a Warming World," *Center for Energy Poverty and Climate*, July 2024, https://energyprograms.org/wp-content/uploads/2024/07/shutoffprotections.pdf.
[56] "Low-Income Energy Affordability Data (LEAD) Tool," *DOE*, n.d. https://www.energy.gov/scep/low-income-energy-affordability-data-lead-tool.

access to tax-exempt financing, and community-oriented governance have produced more stable retail rates than their investor-owned counterparts.[57] In contrast, investor-owned utilities (IOUs) earn a fixed rate of return on their capital expenditures - creating strong incentives to build new infrastructure rather than prioritize maintenance or lower-cost, efficiency-oriented alternatives. Between 2020–2023, IOU retail prices climbed roughly 26%, compared to about 10% for POUs.[58] This divergence offers important lessons for state leaders seeking to manage short-term affordability pressures while preparing for necessary grid expansion.

Load Growth

In the absence of cost containment tools, affordability pressures will intensify as the United States enters its fastest period of electricity demand growth since the 1970s - 1980s.[59] The Federal Energy Regulatory Commission (FERC) estimates peak demand could grow by 2 - 3x through the end of the decade (3% CAGR, 128 GW of new peak demand by 2029), rising as much as ~21.5% by 2035 .[60]

Rapid growth of large, concentrated loads - particularly data centers and new industrial facilities - requires significant T&D investment, often long before new customers fully contribute to the rate base. Without reforms that improve system utilization, accelerate non-wires alternatives, or spread costs more equitably, residential customers risk continuing to shoulder a disproportionate share of the system's rising expenditures.

Load-growth drivers: The primary drivers of the electricity demand 'supercycle' are innovations that will usher in the next wave of American innovation, jobs growth, and competitiveness including:

- *Data Centers:* Compute for artificial intelligence is expected to be the single largest driver of new electricity demand, with BloombergNEF estimating data center power demand will more than double by 2035 (from 35GW in 2024 to 78 GW in 2035) .[61] Hyperscale campuses run 24/7 and require significant firm capacity to support their operations. Lawrence Berkeley National Laboratory (LBNL) projects that data centers will rise from ~4% today to 7–12% of U.S. electricity demand by 2030–2035.[62] Data centers will be essential partners in managing grid congestion, improving system utilization, and piloting new rate designs to help keep prices low for all customers. In the last 12 months, many data center hyperscalers have made public commitments to avoid passing on the costs of their compute infrastructure to ratepayers, acknowledging the critical role they will play in shaping both generation and T&D infrastructure.

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[57] "Assessing California's Climate Policies–Residential Electricity Rates in California," *California Legislative Analyst's Office*, January 7, 2025, https://lao.ca.gov/Publications/Report/4950.
[58] Mark Ellis, "Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities from Overcharging the Public," *American Economic Liberties Project*, January 17, 2025, https://www.economicliberties.us/our-work/rate-of-return/.
[59] John Wilson, Zach Zimmerman, and Rob Gramlich, "Strategic Industries Surging: Driving US Power Demand," *Grid Strategies*, December 2024, https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf.
[60] Norris et al., "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems."
[61] Helen Kou and Nathalie Limandibhratha, "Power for AI: Easier Said than Built," *Bloomberg NEF*, April 15, 2025, https://about.bnef.com/insights/commodities/power-for-ai-easier-said-than-built/.
[62] A. Shehabi, S.J. Smith, A. Hubbard, A. Newkirk, N. Lei, M.A.B Siddik, B. Holecek, J. Koomey, E. Masanet, and D. Sartor, "2024 United States Data Center Energy Usage Report," *Lawrence Berkeley National Lab*, December, 2024, https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report_1.pdf.

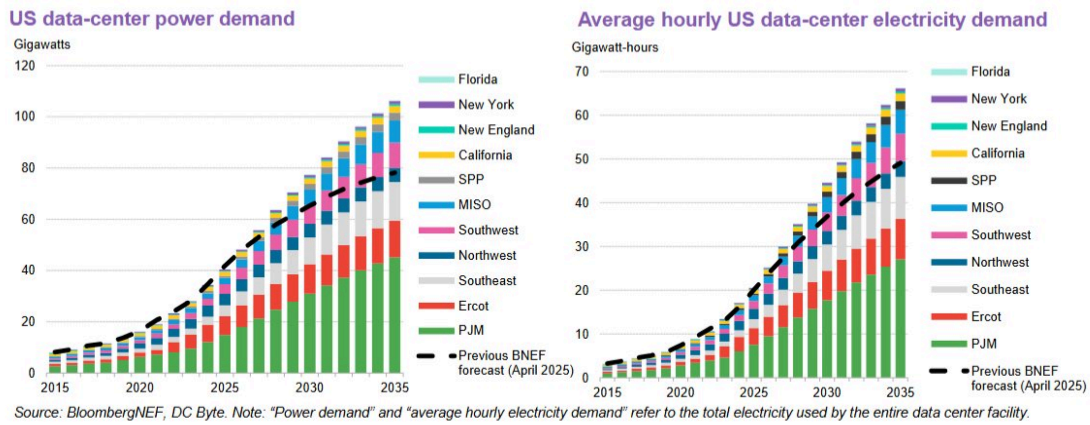

Figure 3: US Data-Center Power Demand and Average hourly US data-center electricity demand
Kou, Helen and Nathalie Limandibhratha. "Power for AI: Easier Said than Built"Bloomberg NEF, April 15, 2025. https://about.bnef.com/insights/commodities/power-for-ai-easier-said-than-built/.

- *Reshoring and reindustrialization:* Federal policies, including the CHIPS and Science Act (CHIPS), Inflation Reduction Act (IRA), and Bipartisan Infrastructure Law (BIL), catalyzed over hundreds of billions in private manufacturing investments since 2021.[63] By 2024, companies had announced more than 900 new manufacturing sites, with activity concentrated in legacy industrial cities (Great Lakes, Midwest), the Southeast, and parts of the Southwest / TX / Mountain West.[64] Many of these emerging load clusters are adjacent to regions of significant data center growth and contribute to major resource-adequacy and transmission-planning challenges - particularly in the Southeast and upper Midwest.[65]

  Although policy uncertainty in 2025 has slowed or paused a subset of these projects - particularly in semiconductors and battery lines - many of the largest facilities are still moving forward. These plants typically require tens to hundreds of megawatts of dedicated load, operate with high uptime (~80–95%), and often require redundant high-voltage service. Taken together, this new industrial base is introducing large, persistent electricity demand that will drive substation expansions, local transmission upgrades, and new interconnection capacity, with substantial downstream implications for retail rates and system planning.
- *Electrification:* The transition to electric vehicles (EVs) and electric heating will also raise the grid's baseline demand. EV charging infrastructure alone is projected to consume ~131 TWh annually by 2030 (roughly 3–4% of total U.S. demand), while widespread adoption of heat pumps and electric appliances is expected to drive a 10% increase in total residential sector electricity consumption over the same period.[66] Unlike 24/7 industrial loads, electrified buildings and vehicles can offer significant flexibility on the demand-side of the grid. For example, smart thermostats and water heaters can shift consumption to absorb excess solar generation around midday and reduce grid strain during evening peaks.

[63] Emily Peck, "Factory Construction Spending Booms under Biden," *Axios*, January 4, 2024, https://www.axios.com/2024/01/04/biden-factory-spending-manufacturing-chips.
[64] Downing et al., "Pathways to Commercial Liftoff: Virtual Power Plants,"; Ana Boyd, Research Fellow, and Todd Olinsky-Paul, "Load Growth: What States Are Doing to Accommodate Increasing Electric Demand," *Clean Energy States Alliance*, July 2025, https://www.cesa.org/wp-content/uploads/Load-Growth.pdf.
[65] Jeff Brown, et al., "Modernizing the U.S. Electricity Grid for Resilience, Load Growth, the Clean Energy Transition, and Energy Security," *Energy Futures Finance Forum*, 2024, https://efifoundation.org/wp-content/uploads/sites/3/2024/05/Modernizing-Americas-Electricy-Grid_FINAL.pdf.
[66] Surya Hendry and Kartik Selvaraju, "Data Centers and EV Expansion Create around 300 TWh Increase in US Electricity Demand by 2030," *Rystad Energy*, June 26, 2024, https://www.rystadenergy.com/news/data-and-ev-create-300-twh-increase-us.

Part III: Structural Barriers to Affordability

Despite growing concerns about affordability, the grid remains structurally inefficient - constrained by underutilization of physical infrastructure, markets that distort efficient outcomes, and regulatory processes that slow or inflate the cost of expansion.

Physical & Technical Barriers

The design and control of physical grid assets contributes to rising costs - challenges include:

- *Underutilization:* The grid is built to accommodate peak load (often the hottest or coldest day of the year) plus a ~15 - 20% planning margin.[67] As a result, most grids operate at ~50 - 55% average utilization, with increases in peak demand triggering significant, capital-intensive upgrades that primarily serve a few hours of extreme annual stress. Without tools to better understand underutilized capacity on the existing grid, shift or flatten demand, increase load flexibility, or better match large customers to underused capacity, states risk locking in another decade of peak-driven investment cycles that raise rates without improving overall system efficiency. As an example, Figure 4 illustrates how 90% of hours the grid operates at 85% or lower utilization nationally.

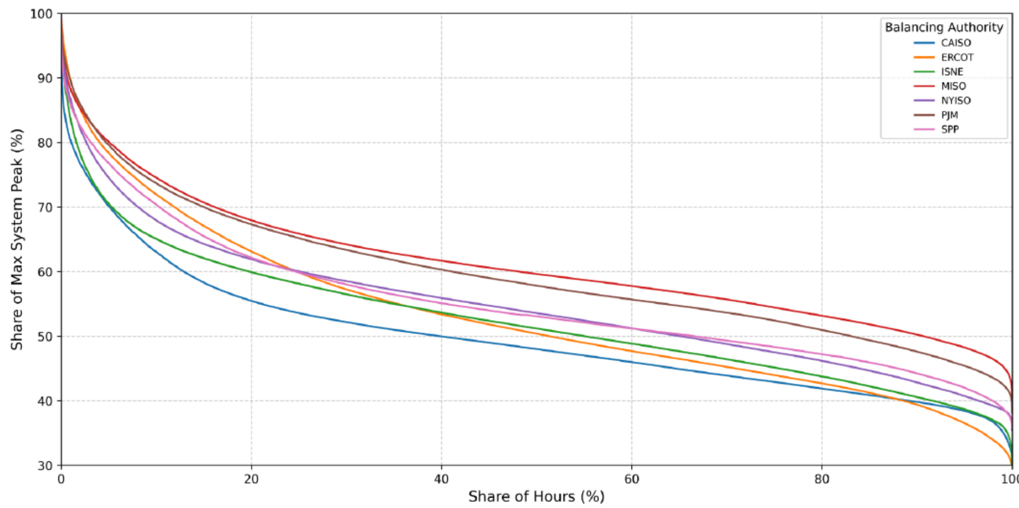

Figure 4: Load Duration Curve for US RTO/ISOs, 2016–2024

Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems." NI R 25-01. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University.
https://nicholasinstitute.duke.edu/publications/rethinking-load-growth

- *Visibility & control at the grid edge:* Utilities rely on two systems to manage the grid in real-time. First, the Supervisory Control and Data Acquisition (SCADA) acts as a hardware control system that provides live monitoring and sends commands for switching lines, voltage control, and opening/closing breakers. Next, the Distribution Management System (DMS) acts as a decision-making layer that sits on top of SCADA and performs advanced voltage optimization, outage management, and power flow modeling. Most SCADA + DMS systems lack both *visibility into* and *control over* millions of distributed devices at the grid edge - especially

[67] For example, a system with average annual load of 50GW may face a summer peak of 90 GW, requiring ~104 GW of capacity (assuming a 15% planning reserve) - that means on a typical day >50GW of the infrastructure is underutilized.

bidirectional assets that can act as load or supply (e.g., electric vehicles, home batteries). Without high-resolution models or feeder-level state estimation, utilities must assume worst-case conditions when evaluating new solar, storage, or large load requests. This leads to conservative hosting-capacity estimates, lengthy manual studies, and upgrade requirements that may not actually be needed. As a result, utilities default to blanket restrictions, queue moratoriums, and costly upgrades - slowing the connection of both DERs and large loads.

- *Information asymmetries:* Utilities have access system data and technical expertise that legislators and PUCs often lack. These information asymmetries can detract from regulators' ability to challenge planning assumptions or pursue lower-cost operational options. Similarly, the information imbalance can drive states toward capital-heavy infrastructure builds as the default response to system uncertainty, even when improved visibility and controls could deliver meaningful increase in reliability at much lower cost. As load growth accelerates, these asymmetries risk translating directly into avoidable increases in customer rates. States can take steps to improve data sharing between utilities and VPP platforms to reduce these gaps and improve systems-level operations for demand-response networks.

Financial & Market Barriers

While many utility and market models were created to support customer affordability and access, in practice these structures frequently delay necessary upgrades, slow new infrastructure development, and distort costs.

- *Utility capital structure:* Utilities capital structure can create a conflict between profitability and ratepayer affordability. Investor owned utilities primarily profit from capital deployment and are financially incentivized to deprioritize software solutions (VPPs, Grid-enhancing technologies) relative to hardware opportunities (wires, substations, etc.). Similar to the 1990s telecom boom, utilities that maximize their rate base at the expense of efficiency solutions risk billions in stranded assets should market conditions around data center deployment cool. IOUs financial incentive towards capital deployment has also made it measurably harder for them to maintain affordability compared to their non-profit peers. Between 2020 and 2023, aggregate IOU rates surged 26.4% - significantly outpacing the 17.7% rise in the Consumer Price Index (CPI). In contrast, Publicly Owned Utilities (POUs), which prioritize cost recovery over profit, kept rate increases to just 10.0%. In real terms, IOU residential rates have risen 49% more than inflation, while POU counterparts managed rate adjustments that were 44% lower than inflation.[68]
- *Market participation:* Prior to 2020, behind-the-meter resources including distributed energy resources (DERs) and virtual power plants (VPPs) were unable to participate in wholesale *capacity* markets - meaning their grid services were undervalued relative to supply-side generation. In 2020, FERC issued a landmark ruling (Order 2222) intended to open wholesale markets to aggregated DERs. However, most RTOs have not fully implemented Order 2222, leaving demand-side flexibility under-compensated and under-deployed relative to its value to the grid.

[68] Mark Ellis, "Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities from Overcharging the Public."

Regulatory & Coordination Barriers

Fragmented authority among federal, state, and regional entities hinders coordinated planning, leaving gaps between who pays for grid upgrades, who benefits, and who controls implementation timelines

- *Interconnection backlog:* The mechanism for connecting new supply is broken. As of late 2023, nearly 2,600 GW of generation - more than double the existing US grid capacity - sits trapped in interconnection queues.[69] The average wait time for interconnect has ballooned from <2 years (2000 - 2007) to >5 years (2018 - 2023), artificially restricting supply and keeping wholesale electricity prices elevated.[70] While interconnection remains a challenge nationwide, Texas (ERCOT) consistently outperforms other regions, using a "connect and manage" approach which has achieved interconnect processing in roughly 1–2 years, compared to 4–6 years in PJM or MISO.[71]

  Regulatory delays are primarily driven by outdated "serial" study processes (evaluating one project at a time) and a lack of coordination between transmission and distribution planning. In response, FERC Order 2023 mandates a shift to a "first-ready, first-served" cluster study model (rather than “first-come, first-served”), requiring developers to post higher financial deposits and demonstrate site control to weed out speculative requests. Crucially, hyperscalers are now exploring "flexible interconnection" agreements - considering accepting a small amount of voluntary curtailment during peak grid constraints in exchange for bypassing years of transmission upgrades. Such an arrangement could bring gigawatts of new load online years ahead of schedule without new wires.

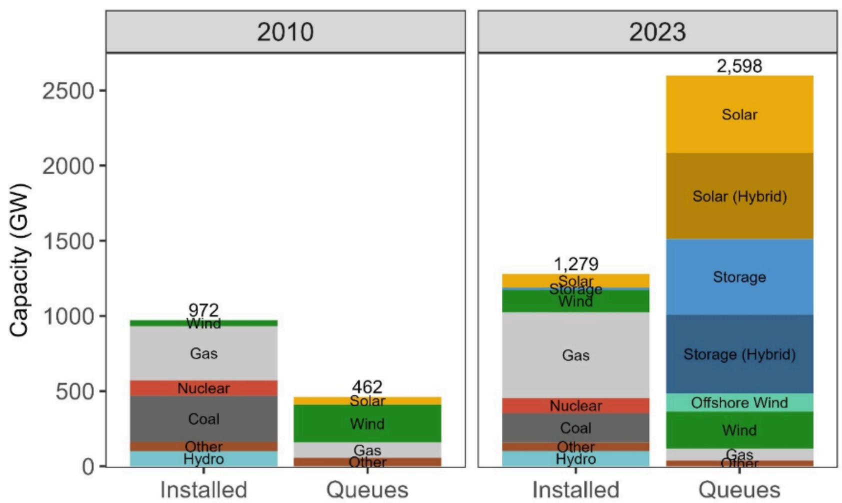

Figure 5: Installed U.S. electric generating capacity compared to interconnection queue capacity

Lawrence Berkeley National Lab. April, 2024. Grid connection backlog grows by 30% in 2023, dominated by requests for solar, wind, and energy storage. [Link](.)

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[69] “Grid Connection Backlog Grows by 30% in 2023, Dominated by Requests for Solar, Wind, and Energy Storage,” *Lawrence Berkeley National Lab*, April 2024, https://emp.lbl.gov/news/grid-connection-backlog-grows-30-2023-dominated-requests-solar-wind-and-energy-storage. Roughly 1,500 GW of queue requests were pre-IRA while more than 1,000 GW were added after IRA credits took effect.

[70] Ibid.

[71] Ibid.

- *Coordination delays and inconsistent frameworks:* Beyond interconnect, projects face a coordination burden across FERC, RTOs, and state PUCs which can add 3 - 5 years to projects, for example:[72]
    - *Inter-region connectivity*: A project connecting to one grid operator (e.g., MISO) often physically impacts the power flows of a neighboring grid (e.g., SPP or PJM). This triggers an "Affected Systems Study" - a secondary, often opaque review process that can add 1 - 2 years to a timeline. Projects are frequently stalled not because of local issues, but because a neighboring RTO hasn't finished its own modeling.

      Multi-state transmission lines may also stall due to disputes over "who pays." A line crossing three states might lower wholesale prices for the entire region, but if the state hosting the steel sees no direct benefit, its regulators (PUCs) are statutorily obligated to reject the costs. This "free rider" problem creates a veto point that can freeze regional infrastructure, forcing developers to build smaller, less efficient local upgrades instead.
    - *Mismatched planning schedules:* State Integrated Resource Plans (IRPs), dictate *generation* build-out (often renewables mandated by state law) while RTO Regional Transmission Expansion Plans (RTEP), dictate *transmission* build-out (focused on reliability). Because these processes run on different multi-year cycles, transmission planners are often designing a grid for a generation mix that is already outdated by the time the plan is published.
    - *Different frameworks & definitions*: Across jurisdictions, regulatory treatment of large loads, DERs, and flexible demand varies widely - even among states in the same RTO. This patchwork of rules for identical technologies can deter large loads from some regions or may incentivize regulatory arbitrage.
- *Affordability oversight:* While utility regulators operate under a legal mandate to ensure rates are "just and reasonable," the traditional regulatory framework lacks structural mechanisms to evaluate the cumulative impact of separate capital programs on a household's monthly budget. Well-intentioned decarbonization or reliability initiatives can still produce stacked rate increases without a mechanism to evaluate their compounding effects. Hawaii and Colorado have begun to experiment with Performance-Based Regulation (PBR), which aims to tie utility earnings to clearly defined performance outcomes (including affordability - see Part IV).

Part IV: Solutions for States

The solutions available to state leaders are commercially ready, have been piloted and scaled by peers, and can be deployed to reduce cost pressures this decade.

Near-term (2026 - 2030)

States can buy time and preserve affordability by maximizing existing grid capacity through coordinated policy levers, including:

- *Scale Virtual Power Plants (VPPs):* Virtual Power Plants (VPPs) have graduated from experimental pilots to proven, cost-effective capacity resources.[73] By aggregating thousands of distributed energy resources (DERs) (e.g., EVs, batteries, smart thermostats), VPPs can provide the same resource adequacy as traditional power

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[72] "U.S. Department of Energy Releases New Reports Highlighting Benefits of Consumer-Centric Solutions for Households, Businesses, and Utilities," *Office of Technology Commercialization, DOE*, January 10, 2025, https://www.energy.gov/technologycommercialization/articles/us-department-energy-releases-new-reports-highlighting.
[73] "U.S. Department of Energy Releases New Reports Highlighting Benefits of Consumer-Centric Solutions for Households, Businesses, and Utilities," *Office of Technology Commercialization, DOE.*

plants at a fraction of the cost.[74] In addition, VPPs can be deployed quickly (~6 - 12 months), at any level of the power system, and to the benefit of all customers, regardless of program enrollment.[75]

In 2023, the Brattle Group found that VPPs are ~40 - 60% cheaper than conventional alternatives (utility-scale batteries, natural gas peakers) for providing resource adequacy and could save ~$15 - 35 billion in capacity investments over the next decade.[76] Similarly, the DOE estimates scaling VPPs 3 - 5x by 2030 (to ~80 - 160 GW) could serve ~10 - 20% of peak load and save power systems $10 billion annually in grid costs.[77] Extrapolating the impact of VPPs to 2035, the Rocky Mountain Institute found that a VPP-portfolio could reduce net generation costs by 20% within a given region, saving ~$140/ each household annually.[78]

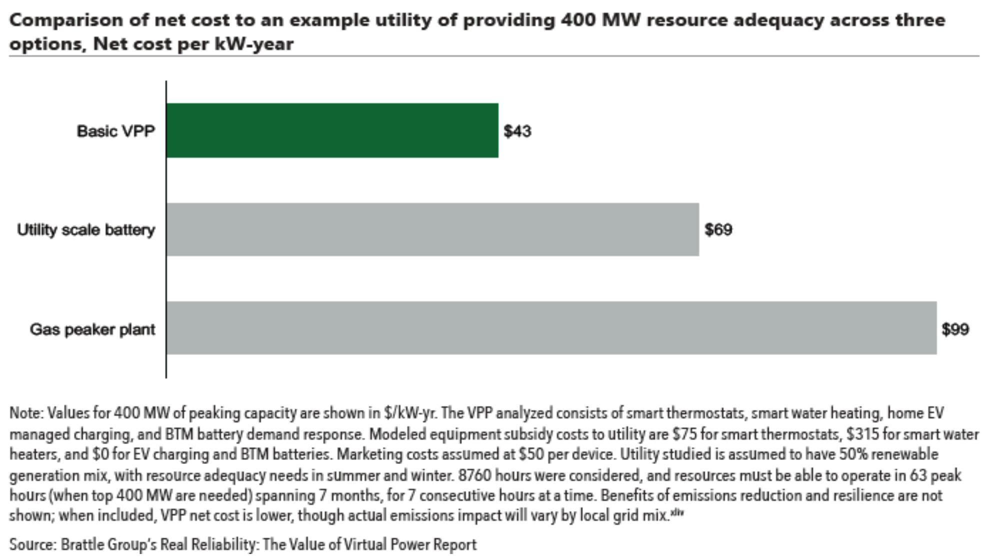

Figure 6: Comparison of net cost to an example utility of providing 400MW of resource adequacy across three options (net cost per kW-year)

The Brattle Group research via US Department of Energy - Pathways to Commercial Liftoff, 2025.

VPP programs grew ~33% from 2024 - 2025 and more than 37GW of VPPs have been deployed nationally (equivalent to 37 nuclear reactors).[79] By size, the four largest VPP programs in the US could each be counted among the ten largest IPPs.[80]

State leaders looking to accelerate VPP deployment should:

[74] "U.S. Department of Energy Releases New Reports Highlighting Benefits of Consumer-Centric Solutions for Households, Businesses, and Utilities," *Office of Technology Commercialization, DOE*.
[75] Jesse Cohen, Lauren Shwisberg, and Mark Dyson, "How Virtual Power Plants Can Help the United States Win the AI Race," *RMI*, November 6, 2025, https://rmi.org/how-virtual-power-plants-can-help-the-united-states-win-the-ai-race/.
[76] Ryan Hledik and Kate Peters, "Real Reliability: The Value of Virtual Power," *Brattle*, May 2023, https://www.brattle.com/insights-events/publications/real-reliability-the-value-of-virtual-power/.
[77] "DOE Releases New Report on Pathways to Commercial Liftoff for Virtual Power Plants," DOE September 2023, https://www.energy.gov/edf/articles/doe-releases-new-report-pathways-commercial-liftoff-virtual-power-plants.
[78] Jacob Becker et al., "Power Shift How Virtual Power Plants Unlock Cleaner, More Affordable Electricity Systems," *RMI*, September 2024, https://rmi.org/wp-content/uploads/dlm_uploads/2024/09/power_shift_report.pdf.
[79] "Virtual Power Plant Capacity Expands 13.7% Year-Over-Year to Reach 37.5 GW, according to Wood Mackenzie," *Wood Mackenzie*, September 17, 2025, https://www.woodmac.com/press-releases/virtual-power-plant-capacity-expands-13.7-year-over-year-to-reach-37.5-gw/.
[80] Emma Penrod, "California, CPower, Enel, AutoGrid, Voltus Dominate Virtual Power Plant Market: WoodMac," *Utility Dive*, March 31, 2023, https://www.utilitydive.com/news/virtual-power-plants-california-wood-mackenzie/646503/.

- *Pursue auto-enrollment:* Simplify VPP enrollment at device purchase (e.g., Arizona's Cool Rewards Program) and mandate opt-out enrollment for households at meter turnover.
- *Stack incentives for DER adoption*: Ensure city and state-level incentives can stack with federal or tribal programs to accelerate purchase and installation of distributed energy resources
- *Require standardization and device interoperability:* Standardize VPP contracting and DER operations across different utility jurisdictions to help entire ISOs / regions speed their transition to large, aggregated VPPs
- *Undergo procurement reform:* Require utilities to evaluate VPPs as supply-side capacity in Integrated Resource Plans (IRPs), competing head-to-head with conventional generation. While some utilities remain wary - often arguing that distributed assets lack firmness or the robustness of a traditional power plant - this skepticism is often resolved after piloting the technology themselves. In practice, VPPs leverage advanced software and high-speed telemetry to respond to grid stress with greater speed and precision than a gas peaker plant. By mandating a fair evaluation process, states can help utilities move past the VPP learning curve and recognize that decentralized networks are an industrial-grade solution for grid stability.
- *Fast-track permitting:* States can consider adopting automated, web-based permitting to issue instant approvals for residential battery and solar installations. In addition, regulators can consider asking utilities to implement "automated interconnection" portals that grant immediate "Permission to Operate" for pre-certified, grid-supportive equipment, bypassing manual engineering reviews for standard systems. By integrating these two reforms, states can collapse a typical three-month administrative cycle into a single day, allowing VPP aggregators to rapidly scale flexible capacity in response to urgent grid needs.

Notable demonstrations & deployments:

State	Example Programs
California	CA hosts nearly 25% of VPPs nationally and the State's Demand Side Grid Support (DSGS) program codified VPPs as a core component of the state's Strategic Reliability Reserve. By empowering the California Energy Commission to procure capacity directly from third-party aggregators (and bypassing slower utility pilot cycles) the state rapidly harmonized incentives for over 75,000 distributed batteries to deliver ~500 MW of reliable capacity during summer peaks. This success demonstrates speed-to-deployment by establishing direct, non-utility procurement pathways that value distributed assets based on verified grid performance Califorina's ChargePerk's program provides customers across 5 utility territories a $50 reward for signing up for managed home charging with the opportunity to save up to $700 per year in charging costs[81]
Texas	ERCOT's *Controllable Load Resource (CLR)* protocol has successfully integrated a wide range of load resources capable of following its real-time dispatch engine[82], including crypto-mining facilities and industrial loads. As of December 2024, ERCOT had more than 6 GW of DERs installed, although active device enrollment may be somewhat lower[83]

[81] "WeaveGrid - ChargePerks California," *DriveClean, California.Gov*, 2026, https://driveclean.ca.gov/node/1228067.
[82] Resources must be capable of following SCED base points.
[83] "Grid Research, Innovation, and Transformation Distributed Energy Resources Operational Data: Value, Insights, and Technology Pathways for a Reliable Grid," *ERCOT*, August 2025, https://www.ercot.com/files/docs/2025/08/29/DER-Operational-Data.pdf.

Minnesota	In a 2024 PUC filing, Xcel Minnesota proposed integrating over 1,800 MW of additional distributed energy resources by 2030 including a program that combines 440MW of solar with 400MW of distributed battery storage[84]
Colorado	Colorado signed into law SB24-21 in 2024,, a law that required major utilities to file VPP proposals (with incentives for participants) by early 2025[85]
Maryland	Under HB 1256, the DRIVE Act, investor-owned utilities in Maryland must develop programs compensating DER owners/aggregators for distribution-system support services, opening the door to VPP structures[86]
Hawaii	Hawaii's utility regulator approved a VPP program for Hawaiian Electric (HECO), sometimes called a "BYOD+" VPP which effectively institutionalized DER aggregation in a tight-grid, high-renewables environment[87]
Illinois *(proposed)*	HB 4120 is under consideration in Illinois and if passed would mandate the state's two largest utilities to propose VPP programs by 2027[88]
Virginia *(pilot-program authority)*	SB 1100 / HB 2346 requires Phase II utilities to propose VPP pilot programs by late 2025 with implementation slated for late 2026 and running through mid-2028. This legislation requires the VPP program to allow residential, commercial, and industrial companies to participate in a VPP pilot either directly or through a 3rd party aggregator[89]

- *Increase grid utilization to make better use of existing infrastructure:* New transmission and distribution (T&D) infrastructure remains the single greatest contributor to rising electricity bills. By optimizing the utilization of existing grid assets, regulators can support utilities in 'right sizing' infrastructure investments and defer some multibillion-dollar projects, sparing ratepayers from unnecessary costs. Even marginal gains in efficiency, such as re-routing power through underutilized lines or using technology to manage localized peak loads, can deliver outsized affordability benefits when scaled across the entire system. For example, recent analysis has shown potential capital savings at the billion dollar-scale in certain service territories based on the ability to target load reduction to the number of feeder overloads addressed and to relative feeder upgrade costs based on location.[90]

  As the global hub of data center development, Virginia is pioneering a regulatory shift to focus on grid utilization as a key affordability frontier. The administration of the recently elected Governor Abigail Spanberger identified grid utilization as one pillar of the energy platform making up the Governor's 'Affordable Virginia Agenda.'[91] In February 2026, House Bill 434 (HB 434) passed the House of Delegates unanimously and its Senate counterpart, Senate Bill 621 (SB 621), passed the Virginia Senate along party-lines. The legislation is expected to be signed into law this spring. The legislation empowers Virginia's State Corporation Commission to establish formal grid utilization metrics based on data submitted by major utilities in October 2026 and requires that

[84] "Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan (IRP)," *Minnesota Public Utilities Commission*, 2025, https://mn.gov/puc/activities/economic-analysis/planning/xcel-energy-irp/; Frank Jossi, "Xcel Minnesota Looks to Mimic Power Plants with Solar and Storage," *Canary Media*, August 28, 2024, https://www.canarymedia.com/articles/virtual-power-plants/xcel-minnesota-looks-to-mimic-power-plants-with-solar-and-storage.
[85] "Virtual Power Plants." *National Conference of State Legislatures*, November 8, 2024. https://www.ncsl.org/energy/virtual-power-plants.
[86] "Virtual Power Plants." *National Conference of State Legislatures*.
[87] Brian Lips, "What Are States Doing to Make Virtual Power Plants a Reality?," *DSIRE Insight*, April 26, 2024, https://www.dsireinsight.com/blog/2024/4/26/making-virtual-power-plants-a-reality.
[88] Kari Lydersen, "Virtual Power Plants May Soon Provide More Electricity to Illinois' Grid," *Canary Media*, September 25, 2025, https://www.canarymedia.com/articles/virtual-power-plants/illinois-legislation-customer-battery-incentives.
[89] "SB1100 - 2025 Regular Session," *State of Virginia, Legislative Information System*, May 2, 2025, https://lis.virginia.gov/bill-details/20251/SB1100.
[90] "California Load Management Standard Avoided Distribution Grid Upgrade Study," *GridLab and Kevala*, August 2025, https://gridlab.org/wp-content/uploads/2025/08/GridLab_Kevala_CA-Load-Management-Standard.pdf.
[91] *See* "Governor-Elect Spanberger, General Assembly Leaders Announce Key Legislative Priorities to Lower Costs for Virginia Families," *Office of the Governor-Elect of Virginia*, December 18, 2025, https://spanbergertransition.com/news/governor-elect-spanberger-general-assembly-leaders-announce-key-legislative-priorities-to-lower-costs-for-virginia-families/.

regulators establish a process in evaluation of future IRPs for evaluating utilities' progress in increasing energy utilization of the existing grid, ensuring grid investments already funded by customers are being used to their maximum potential.[92] Notably, the law is technology neutral and does not mandate utilities to select specific technology or resource choices. Instead, the legislation establishes a measurement and accountability framework that allows regulators to more effectively establish if grid assets across the distribution and transmission system are being used efficiently before approving new capital expenditures. The legislation also dovetails with the deployment of non-wires alternatives, including grid-enhancing technologies, virtual power plants or other DERs, energy storage, and demand response, requiring the regulator to track progress on grid utilization through these mechanisms in annual reporting. In addition, the law is complementary to the goals of legislation being explored last year and in the 2026 General Assembly session related to evaluating load flexibility options to address demand from large loads.

Several states have previously advanced legislation or regulatory actions that strive to identify opportunities to defer utility grid distribution and transmission infrastructure, albeit many of those efforts directly evaluate the potential for DERs to replace new build or do not directly target measured increases in utilities' use of existing T&D infrastructure. For example, in Illinois, Senate Bill 25 reforms the state's integrated resource plans to in part "optimize utilization of electricity grid assets and resources to minimize total system costs." The bill further establishes that IRPs should include a review of how utilities plan to use energy storage, VPPs, distributed energy storage, energy efficiency, demand response, time of use rates, and other technologies or methods to address resource adequacy and support cost-effective and affordable electricity delivery. [93] In addition, the California Public Utility Commission's Distribution Investment Deferral Framework (DIDF) process requires major regulated utilities in the state to file annual Grid Needs Assessments and Distribution Deferral Opportunity Reports. Within the filings, the three largest California utilities propose a list of DER opportunities most likely to successfully defer a traditional grid investment.[94]

State leaders looking to increase grid utilization should:

- *Establish transparent, measurable metrics to evaluate grid utilization*: Policymakers and regulators can only evaluate effective use of existing T&D infrastructure if they first have an established regulatory process to identify data needs at the feeder and substation level, compel regulated utilities to comply with data sharing requirements, and are required to provide a regulatory pathway for implementing those metrics in future cost recovery / requests from utilities to build new infrastructure.
- *Support and scale front-of-the-meter DERs / storage:* States should support proven and scalable distributed energy resources that can be deployed today. One example of this kind of front-of-the-meter DER solution increasingly being adopted by states across the country is community solar and storage, or mid-scale solar projects (~1 - 5 MW installations) paired with battery storage, interconnected to the local distribution grid. Instead of serving a single

[92] *See* "More Than Half of Governor Spanberger's "Affordable Virginia Agenda" Passes Virginia House of Delegates or Senate," *Office of the Governor of Virginia*, February 9, 2026, https://www.governor.virginia.gov/newsroom/news-releases/2026/february-/name-1112416-en.html.
[93] *See* Illinois Senate Bill 25, https://www.ilga.gov/Legislation/BillStatus/FullText?GAID=18&DocNum=25&DocTypeID=SB&LegId=157124&SessionID=114.
[94] *See* "High DER Future Grid Proceeding," *California Public Utilities Commission*, n.d., https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning.

property, these projects allow hundreds of nearby utility customers, including renters, multifamily residents, small businesses, and others to subscribe and receive monthly bill credits for clean electricity produced. Community solar and storage offers a dispatchable solution as batteries charge using co-located solar and discharge during expensive evening hours when the grid is most stressed, and can be permitted and built in 12 - 24 months on small parcels such as fallowed farmland, brownfields, or commercial rooftops. Interconnection at the distribution-level on the utility-side of the meter sidesteps the siting, permitting, and infrastructure barriers slowing large-scale projects. Community solar and storage can also support electricity affordability head on: recent analysis of the California grid found that 5.4 GW of community solar and storage deployed across CAISO would save ratepayers approximately $6.5 billion over 20 years through lower wholesale prices, reduced procurement needs, and deferred transmission investment.[95] States should look for opportunities to create programs for distributed, front-of-the-meter batteries, and complementary front-of-the-meter solar, in order to defer distribution costs, particularly in congested parts of the grid. These projects can help reduce peak capacity costs, increase grid utilization, and avoid expensive upgrades including for peakers and wires.

- *Pursue VPPs, GETs:* Virtual Power Plants (VPPs) and Grid-Enhancing Technologies (GETs) are both critical solutions that support higher grid utilization. GETs use sensors and software to safely push more electricity through existing wires based on real-time conditions. VPPs complement GETs by aggregating thousands of distributed batteries and smart devices to "shave" demand peaks and fill in "valleys" of low usage. Together, these solutions can deliver more electricity through existing infrastructure and make use of infrastructure during periods of the day when 'headroom' is identified in the system.

Notable demonstrations & deployments:

State	Example Programs
Virginia	HB 434 / SB 621 is a first-of-its kind bipartisan effort that requires: 1 - Utilities to propose grid utilization metrics 2 - Regulatory review of utilization metrics as part of integrated resource plans (IRPs) 3 - Annual reporting to the Virginia General Assembly and Governor regarding utilities' performance against grid utilization metrics 4 - Direct evaluation of non-wires alternatives including, but not limited to, energy storage resources, customer-provided capacity, grid-enhanging technologies, utility-owned distributed energy generation, or virtual power plants
Illinois	Passed SB 25 which would revise multiyear IRP reviews to include a focus on utilization of electricity grid assets and resources to minimize total system costs.
California	The CPUC's Distribution Investment Deferral Framework(DIDF) process requires certain annual filings by the major regulated CA utilities such as a Grid Needs Assessment and Distribution Deferral Opportunity Reports, which includes identification of DER opportunities most likely to successfully defer a traditional grid investment.

- *Flexible, large load integration:* To manage the surge in high-density demand without overbuilding capacity, regulators should establish "interruptible" or "flexible" service classes for hyperscale loads. Rather than treating these loads as firm, utilities can offer reduced rates in exchange for the ability to curtail consumption during limited peak events. Through a 'Bring Your Own Capacity' (BYOC) model, large new

[95] "The Value of Community Solar and Storage in CAISO," *Aurora Energy Research Ltd.*, April 2025, https://communitysolaraccess.org/wp-content/uploads/CCSA-Aurora-CCSA-final-report-v3.pdf.

customers secure capacity via clean PPAs, on-site generation, storage, or VPPs, and then make that capacity available to the system to meet reliability requirements tied to receiving faster interconnection. This approach removes years of delay from the queue, ensures the customer covers its incremental supply costs, and avoids shifting new infrastructure costs onto existing ratepayers, while still preserving full system reliability.

In December 2025, a Princeton study of BYOC found that combining flexible grid connections with BYOC procurement could allow large data centers to connect 3–5 years faster while largely eliminating cost shifting to other customers.[96] Modeling across six PJM sites determined that grid power would remain available >99% of the year, with on-site resources dispatched only 40–70 hours annually, while avoiding 273 MW of new capacity build and $78 million in system costs per GW of load under flexible interconnection. Crucially, BYOC enables data centers to directly procure accredited generation, internalizing roughly $326 million/GW of capacity costs and, combined with energy payments, covering ~96–100% of their incremental system costs (~$733 million/GW).[97] While further modeling is required, this work illustrates that large new loads can be added without materially raising rates for other customers, while higher utilization of existing grid assets spreads fixed costs and helps ease overall rate pressure.

In October 2025, the U. S. Department of Energy (DOE) took steps to elevate this same challenge nationally - directing FERC to "initiate rulemaking to rapidly accelerate the interconnection of large loads".[98] In public comments filed at FERC, data center hyperscalers expressed modest support for a more standardized process but emphasized large load curtailment should be used as an *optional incentive* to speed interconnection requests. Grid operators urged FERC not to overstep its jurisdiction or duplicate state-driven interconnection processes.[99]

Notable demonstrations & deployments:

State	Example Programs
Texas	The Electricity Reliability Council of Texas (ERCOT) operates on a 'Connect and Manage' approach that allows new generators (including some large loads) to connect to the grid before all long-term transmission upgrades are built - with the understanding their output may be curtailed during congestion or reliability events[100]
Arizona	Salt River Project demonstrated data load center flexibility using AI software in May 2025 with an estimate that software can reduce power consumption for AI workloads by ~25% over 3-hours during a grid stress event[101]

- *Rate design:* Pricing structures should evolve to reflect the true, time-varying cost of energy delivery and to protect ratepayers from cross-subsidizing new industrial demand.
    - *Time-of-use pricing:* States can default to time-of-use (TOU) rates with significant on-peak/off-peak price differentials to reward load shifting. Critically,

[96] Brancucci et al., "Flexible Data Centers: A Faster, More Affordable Path to Power."
[97] Brancucci et al., "Flexible Data Centers: A Faster, More Affordable Path to Power."
[98] "U.S. Department of Energy Releases New Reports Highlighting Benefits of Consumer-Centric Solutions for Households, Businesses, and Utilities," *Office of Technology Commercialization, DOE.*
[99] Ethan Howland, "DOE Large Load Interconnection Proposal Sparks Federal-State Jurisdiction Concerns," *Utility Dive*, November 24, 2025, https://www.utilitydive.com/news/doe-large-load-interconnection-ferc-naruc/806278/.
[100] J. Fernandes, "ERCOT Interconnection Process: Generation Entity Winter Weather Preparedness Workshop." *ERCOT*, October 2024, https://www.ercot.com/files/docs/2024/10/30/0940-AM-ERCOT-Interconnection-Process-Generation-Entity-Winter-Weather-Preparedness-Fernandes.pdf.
[101] Herman Trabish, "Utilities, Regulators Look to Accelerate Pilots to Achieve Speed-To-Innovation," *Utility Dive*, December 1, 2025, https://www.utilitydive.com/news/regulatory-sandbox-dcflex-vpp-pura-pilot-project/806454/; Mark Spieler, "How AI Factories Can Help Relieve Grid Stress." *NVIDIA*, July 1, 2025, https://blogs.nvidia.com/blog/ai-factories-flexible-power-use/.

VPPs and Demand Response (DR) should be treated as supply-side capacity resources in procurement planning, competing directly with traditional generation.

- *Large load tariffs:* States are implementing specialized tariffs that enforce strict cost recovery for some of the newest, largest loads. For example, in AEP's Ohio service territory, recently approved tariffs require data centers to pay for 85% of their contract demand monthly (even if usage is lower), protecting the utility from stranded assets. In Nevada, NV Energy's service territory has implemented a Clean Transition Tariff that matches loads with dedicated new clean energy resources to ensure new demand funds its own supply.

Notable demonstrations & deployments:

State	Example Programs
Ohio	Effective July 2025, AEP's Ohio Data Center Tariff will require data centers to pay minimum demand charges (at least 85% of contracted demand)
Georgia	Georgia's PSC allows for special contract terms and billing rules for large customers (typically data centers or industrial customers with loads above 100MW)
Virginia	Beginning January 1, 2027 - Virginia will require minimum payments of ~85% of contracted T&D demand and ~60% of generation demand
Texas	Texas' SB6 requires loads > 75MW to meet interconnection standards including curtailment readiness to shift risks away from households during emergencies
Nevada	Nevada's Clean Transition Tariff allows large loads to pay a premium for power generated from emerging energy technologies to avoid cross-subsidizing any first-of-a-kind, next-generation, clean, firm solutions

- *Pursue permitting reform:* Faster permitting would expand generation, transmission, and distribution capacity across the grid. States can take steps to fast-track permitting through statutory 'shot clocks' that mandate permit decisions with fixed periods (e.g., ~12 months for municipal reviews, 15 months for state-level listing). States can also streamline processes by establishing centralized siting authorities that would offer a single, consolidated application process to replace fragmented local approvals. Additionally, states can designate pre-cleared 'Energy Opportunity Zones' in areas with low environmental impact, allowing developers to utilize categorical exclusions and programmatic environmental reviews to by-pass years of site-specific litigation.

Medium-term (2030 - 2035)

Beyond 2030, long-term affordability depends on modernizing grid planning and market design: integrating flexibility into resource adequacy standards, expanding high-value transmission corridors, and coordinating infrastructure investment with decarbonization goals.

- *Deploy grid-enhancing technologies (GETs):* States should deploy grid-enhancing technologies including reconductoring of the existing transmission network, dynamic line rating (DLR), and advanced power-flow controls, particularly in the highest load-growth corridors. Studies have shown that reconductoring can increase capacity by more than 100% on existing rights of way (with limited additional permitting)[102] while DLR systems can increase line capacity as much as 70%.[103] Deploying GETs also creates high demand for skilled labor, including tradespeople who have the expertise to work on high-voltage lines. In addition, specialized training and apprenticeship programs provided by unions can ensure that the next generation of technicians are prepared to upgrade critical infrastructure efficiently and reliably.

Notable demonstrations & deployments:

State	Example Programs
Texas	As part of its 2026 - 2030 transmission improvements, ERCOT is evaluating opportunities for reconductoring (including live reconductoring) across its 345 kV lines[104]
MISO	MISO is undergoing reconductoring as part of reliability initiatives on its Columbia 138 kV transmission lines, expected to be complete in June of 2027[105]
California	California's Independent System Operator (CAISO) has approved a variety of GETS projects including five advanced conductor projects, five new flow control projects, and three new voltage control projects to facilitate cost savings, reduce congestion, improve reliability, and increase utilization of existing assets[106]

- *Deliver incremental generation:* Where available, states should encourage generators to unlock existing firm, low-carbon capacity from uprates and restarts of hydropower and nuclear facilities. Uprates have been the primary driver of new US nuclear capacity for decades, with roughly ~8GW of uprates approved to date across the US nuclear fleet.[107] Uprates can take a few years to plan and execute, in part because plants may need to wait until their refueling cycle for more extensive changes to system configurations (e.g., changes to turbines, pumps, or transformers). States looking to deliver uprates by the early 2030s will likely need to submit applications to Public Service Commissions within the next ~12 - 24 months, meaning planning for these expansions should begin today.

Notable demonstrations & deployments:

Initiative	Description
Nuclear uprates	Numerous utilities and nuclear operators are hoping to get more out of their existing fleet, with large, publicly listed IPPs noting the importance of life extensions and uprates including on public earnings calls[108]
Nuclear restarts	While limited, restarts of nuclear facilities including Duane Arnold, Crane Energy Center, and the Palisades nuclear plant represent opportunities to add gigawatts of firm capacity back to the grid by the early 2030s
Hydro uprates and restarts	Hyperscalers are investing in improving the existing US hydropower fleet through maintenance and uprates that could help improve the efficiency and output of legacy facilities[109]

[102] Chojkiewicz et al., "Accelerating Transmission Capacity Expansion by Using Advanced Conductors in Existing Right-of-Way," *Proceedings of the National Academy of Sciences* 121, no. 40, (September 23, 2024), https://doi.org/10.1073/pnas.2411207121.
[103] Chojkiewic et al., "2035 and beyond Report: Reconductoring;" "Advanced Transmission Technologies," *DOE*, December 2020. p. 9, https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf.
[104] "2024 Regional Transmission Plan (RTP) 345-KV Plan and Texas 765-KV Strategic Transmission Expansion Plan Comparison," *ERCOT*, 2025, https://www.ercot.com/files/docs/2025/01/27/2024-regional-transmission-plan-rtp-345-kv-plan-and-texas-765-kv-strategic-transmission-expans.pdf.
[105] "MISO 2nd West Subregional Planning Meeting," *Midcontinent Independent System Operator (MISO)*, June 5, 2025, https://cdn.misoenergy.org/20250605%20WSPM%20Item%2004b%20Review%20of%20Proposed%20Reliability%20Projects%20ATC%20DPC%20NWEC%20RPU700728.pdf.
[106] Danielle Mills and Jeff Billinton, "AB 2779 Grid Enhancing Technologies." *California Independent System Operator (CAISO)*, August 4, 2025, https://stakeholdercenter.caiso.com/InitiativeDocuments/AB-2779-Grid-Enhancing-Technologies-Report-2024-2025-Transmission-Planning-Process.pdf.
[107] "Planning a Reactor Power Uprate Time to Get in Line at the NRC," *Morgan Lewis*.
[108] "Constellation Reports Second Quarter 2025 Results," *Constellation Energy*, August 7, 2025. https://www.constellationenergy.com/newsroom/2025/08/constellation-reports-second-quarter-2025-results.html.
[109] Heather Clancy, "Google's Unique $3 Billion Hydropower Contract Will Not Be the Last," *Trellis*, July 22, 2025, https://trellis.net/article/googles-unique-3-billion-hydropower-contract-wont-be-the-last/.

Long-term (2035+)

States should begin laying the groundwork for policy proposals that will speed the construction of clean, firm generation, hasten interconnect, and re-align utility incentives to reward technology adoption and asset utilization over the long-term.

- *Build the fleet of the future:* States must scale low-carbon, firm assets including next generation geothermal, utility-scale renewables with battery storage, nuclear (Gen III and Gen IV designs), and carbon capture and utilization systems on the existing natural gas fleet. To do so, the United States will need to leverage the skilled trades as a ready-made workforce and expand the footprint of highly technical, skilled workers. Many next-generation grid assets are expected to see cost-downs from repeatable scale. Trades will play a critical role in driving labor efficiency at megaprojects and reinvigorating the expertise required to build large projects quickly and effectively.

Notable demonstrations & deployments:

Initiative	Description
Nuclear greenfield pilots	POUs including the Tennessee Valley Authority and the state of Michigan have received grants from the US Department of Energy to explore small modular reactor (SMR) pilots in their jurisdiction while the Western Interconnect is partnering with venture-backed technology firms to build advanced reactors in their territory
Geothermal	States including California, Texas, Utah, Nevada, and Colorado have taken steps to expand geothermal power, including through Geothermal Energy Tax Credits (Colorado) and initiatives like Nevada's Clean Transition Tariff (which has helped support some of the first scaled deployments of enhanced geothermal in the state)
CCUS	Numerous states are pursuing primacy to help streamline permitting of Class VI wells for carbon capture, utilization, and sequestration - with Louisiana, Texas, West Virginia, and Arizona all granted primacy since 2023 - a step that is likely to lead to accelerated deployments in these jurisdictions
MDES / LDES	As of early 2026, the first commercial-scale long-duration projects are hitting the grid, including companies providing 100-hour iron-air batteries at retiring coal sites in Minnesota and Georgia and iron-flow pilots in Arizona and Alaska designed to provide 10–12 hours of discharge

- *Reform planning and utility incentives:* Align utility incentives with policy objectives beyond capital spending - including asset utilization and technology adoption. States including Hawaii and Colorado are taking steps to modify their core utility regulation through performance-based measures. PBR ties utility earnings to clearly defined performance outcomes (not just capital spending) by using metrics, financial incentives, and multi-year rate plans. The goal is to align utility behavior with policy objectives such as cost control, reliability, DER integration, clean energy, and customer service.

Notable demonstrations & deployments:

Initiative	Description
Colorado	Colorado has adopted aspects of performance-based ratemaking including earnings adjustments tied to clean energy, DERs, and system efficiency
New York	New York implemented its Reforming the Energy Vision which includes earnings adjustment mechanisms and incentives tied to system efficiency, peak reduction, and DER integration

Hawaii	Hawaii has implemented the most comprehensive performance-based regulation (PBR) model in the US to replace its cost-of-service framework - incentives are tied to affordability, DER integration, reliability, and interconnection speed in a state with the highest retail electricity rates nationally

Conclusion

The United States has transformed its energy system before - from rural electrification initiatives of the 1930s to the shale revolution of the 2010s. Before the end of this decade, states should take aggressive steps to deploy proven, cost-effective technologies (VPPs, DERs), increase the utilization of existing grid assets, and reform incentives systems that slow or undermine efficient infrastructure expansion. Over time, states should take additional steps to deploy grid-enhancing technologies (GETs), pursue restarts and uprates where feasible, and invest in the efficient, decarbonized fleet of the future. By unleashing American electrotech at scale, states can shift from a planning and financing model that rewards spending to one that rewards efficiency, capturing a generational infrastructure boom while delivering affordable, reliable power for all customers.