Author

Global **Transmission** Report

Knowledge Partner

HITACHI

GRIDS IN TRANSITION: US

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EXECUTIVE SUMMARY

The US electricity system is facing its most consequential challenge in a generation. After more than a decade of modest demand growth, consumption is rising sharply, driven by data-center expansion, industrial reshoring, and the electrification of transport, buildings, and manufacturing. The generation portfolio is evolving in parallel. Renewable deployment continues to accelerate, natural gas remains important for dispatchable capacity, and nuclear investment is drawing renewed policy attention. Electricity is becoming a strategic enabler of economic development, digital infrastructure expansion, and industrial competitiveness.

Electricity sales grew 4.7% between 2023 and 2025[1], more than the preceding seven years combined. The Energy Information Administration (EIA) projects a further 14% growth through 2035[2]. Data centers are driving most of this increase. US data-center electricity consumption reached an estimated 192 TWh in 2024, or 4.7% of the total consumption[3]. Lawrence Berkeley National Laboratory (LBNL) projects this to rise to anywhere between 521 TWh and 843 TWh by 2030, depending on the pace of artificial intelligence (AI) adoption[3]. The Department of Energy's (DOE) resource adequacy modeling shows a comparable pattern. Coincident peak load is projected to grow 2.3% annually through 2030, as compared to 1.1% annually if data centers are excluded[4]. This growth is also geographically concentrated, mostly in Virginia and Texas, straining resource planning and network expansion in already congested regions.

While transmission grid spending has increased recently, years of underinvestment have left the grid ill-equipped for the scale, location, and operating characteristics of this new demand. Transmission development has not kept pace with changes in generation and load patterns, distribution networks are managing more complex two-way flows from rooftop solar and battery storage, and resource adequacy margins have narrowed as rising demand outpaces new firm capacity.

The grid must now transmit larger volumes of power across wider areas, remain stable second to second, stay adequately resourced for peak demand through seasons and years, withstand a wider range of weather extremes, and continue operating through cyberattacks and physical threats. These pressures are testing the system across five dimensions: network capacity, stability, resource adequacy, flexibility, and resilience.

The consequences are already visible. Transmission congestion cost an estimated $12 billion in 2024[5]. Curtailment of generation due to the grid's inability to adequately match supply and demand has risen sharply in California and Texas, where generation has outpaced local transmission capacity. In July 2026, a routine transmission fault in Northern Virginia triggered the unexpected transfer of around 3.8 GW of data-center load to backup generation, causing significant voltage and frequency disturbances[6]. These are signs of the operational challenges that accompany high concentrations of critical demand. If not addressed on time, these constraints will delay industrial expansion, slow electrification, and raise electricity prices.

Addressing these challenges will require coordinated progress across four areas.

Planning and permitting reforms need to support both near-term and long-term delivery. In the near term, more dynamic planning approaches can help identify congestion risks, anticipate large-load growth, and accelerate deployment of grid-enhancing technologies. Over the longer term, regional planning processes, permitting reform, and interregional coordination remain essential to deliver the major transmission investments required for a more resilient and interconnected grid. Federal Energy Regulatory Commission (FERC) Order 1920 provides a framework for longer-term regional planning, and the DOE's Coordinated Interagency Transmission Authorizations and Permits (CITAP) program, along with pending permitting reform, can further shorten project timelines.

Mature and advanced technologies, including advanced conductors, dynamic line rating (DLR), high-voltage direct current (HVDC), grid-forming inverters, synchronous condensers, and battery storage, need to be deployed faster to add usable capacity to the existing network and to help operators manage a system increasingly built around power electronics.

The supply chain needs to be strengthened alongside this investment. Large power transformer lead times approaching three years are constraining delivery. Investments and incentives to support domestic manufacturing capacity, supplier diversification, and standardized technical specifications are needed to improve delivery certainty.

Market design and regulation need to keep pace with this changing system. Wholesale markets must be opened further to storage, aggregated distributed resources, and flexible demand. Grid codes should reflect the operational characteristics of a more diverse generation portfolio.

These four priorities reinforce one another. Coordinated planning directs capital to the most economic and beneficial projects. Technology turns that capital into usable capacity. A resilient supply chain ensures equipment arrives when needed. Market reform allows that capacity to recover its true economic value. Generation investment remains necessary, but it cannot deliver its benefits without a network able to connect and move that power efficiently.

US federal policy on power generation has evolved to focus on dispatchable capacity and energy dominance. The rules governing how the grid is planned, connected, and operated have remained broadly consistent, with an increasing focus on accommodating rapidly growing large loads, particularly AI data centers. This institutional continuity, more than the direction of generation policy, will determine whether the grid can deliver the needed infrastructure while maintaining affordability, reliability, and competitiveness. ■

Figure 1: The US Electricity Grid in Transition

DEMAND & SUPPLY

+14%
Electricity demand growth by 2035 (+37% by 2050)

192 TWh→521-843 TWh
Data center demand (2024 actual → 2030 range)

+224 GW
Coincident peak demand growth over the next decade (NERC)

3.4 TWh + 8 TWh
Curtailed in CA (2024) + Curtailed in TX (2024)

GRID UNDER STRESS

13 of 23
NERC regions at elevated resource adequacy risk

$12 billion
Transmission congestion costs (2024)

3,800 MW
Load disconnected in Northern Virginia in July 2026

1,162/3,500
Cyberattacks (2024) / Physical incidents (2025)

INFRASTRUCTURE & INVESTMENT

>$270 billion
Estimated transmission investment, 2026–2030

1,312 GW + 749 GW
Generation + storage in interconnection queue

30,764 circuit-miles
Transmission network planned by 2038

70%
Of transmission lines are more than 25 years old

PATH TO DELIVERY

Integrated & Coordinated Planning

Advanced Technology

Supply Chain Resilience

Policy & Market Reform

INTRODUCTION

1

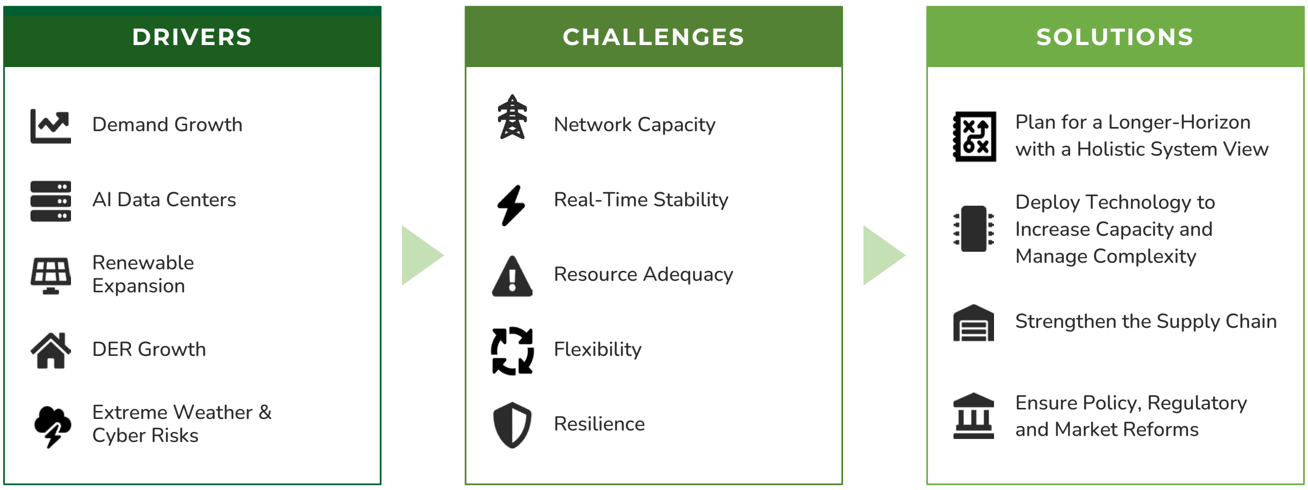
The US electricity system is entering a period of transformation unlike anything seen in recent memory. After more than a decade of modest demand growth, electricity consumption is now rising sharply, driven above all by the rapid expansion of data centers, and reinforced by the broader electrification of transport, buildings, and industry.

The US power generation mix has been evolving to meet rising demand and in response to changing policy priorities and resource economics. Utilities and policymakers are comparing the roles of renewables, natural gas, and nuclear power, weighing each against cost, reliability, and delivery timelines.

At the same time, the power delivery network is undergoing a fundamental change. The existing grid was built around a small number of large, centralized power plants supplying predictable demand through one-way flows. This system must now accommodate a more complex operating environment arising from the expansion of variable renewable generation, the connection of large loads that can appear and disappear within seconds, and two-way flows from distributed energy resources.

This report examines that transformation in four parts. It first explains the demand, supply, and structural developments reshaping the US electricity system. It then evaluates the operational challenges these developments create for network capacity, real-time stability, resource adequacy, flexibility, and resilience. Next, it reviews the transmission investment needed to meet the demands of this transformation. Finally, it identifies the planning, technology, supply chain, and policy measures needed to deliver that investment reliably and on time. ■

Figure 2: Drivers, Challenges, and Actions for Transitioning Grid



DRIVERS RESHAPING THE US POWER GRID

2

The US electricity system is undergoing its most significant transformation in decades. Following a prolonged period of relatively flat demand, consumption is rising sharply, new generation is being built at an unprecedented speed, and networks engineered for a different era are being asked to accommodate operating conditions they were not designed for. These developments are occurring at the same time and largely in the same regions, producing challenges beyond what any single trend would create alone.

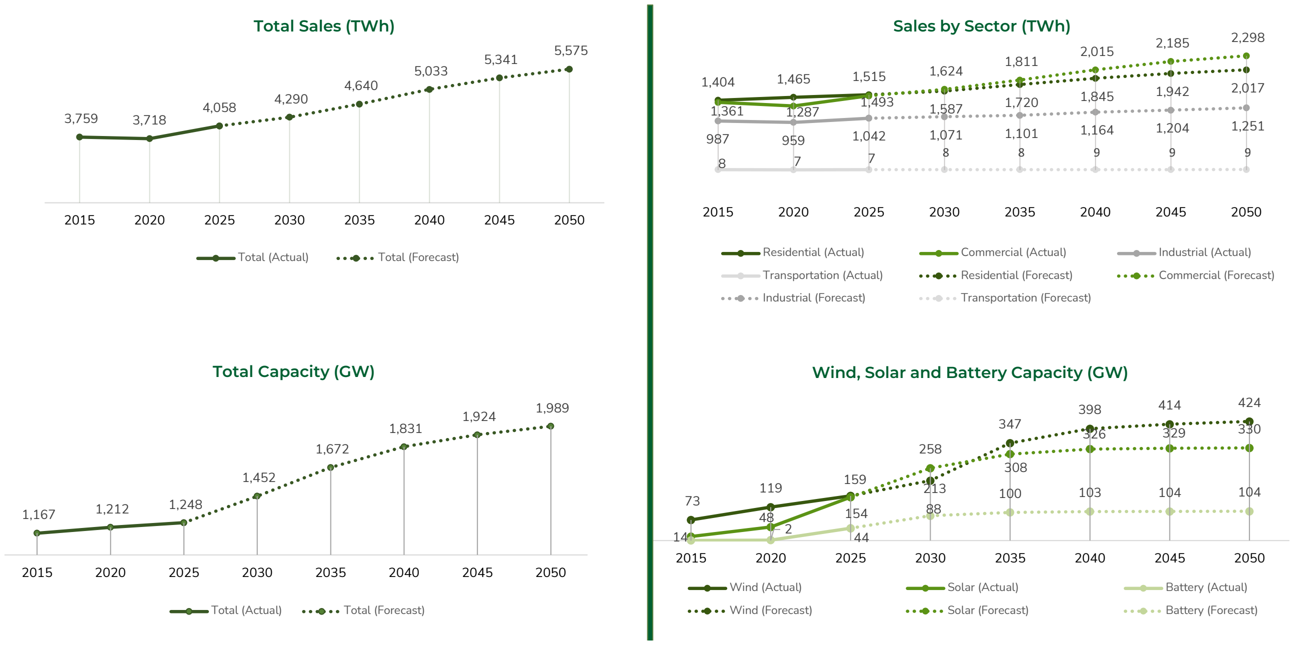
Demand growth has returned, and faster than previously assumed. US electricity sales grew at an average annual rate of just 0.4% between 2015 and 2023[1]. Between 2023 and 2025, sales rose by about 4.7%, exceeding the cumulative growth of the previous seven years[1]. The Energy Information Administration's (EIA) Annual Energy Outlook 2026 projects sales to rise roughly 14% between 2025 and 2035, and by a further 20% between 2035 and 2050[2]. Commercial demand, the category recording data-center load, is expected to grow fastest of all end-use sectors, at roughly 2.1% annually through 2035[2] and remain the fastest-growing segment through mid-century.

Data centers and AI-related load are the principal drivers of this demand growth. US data-center electricity consumption rose 14% between 2023 and 2024, reaching an estimated 192 TWh, or 4.7% of total US consumption[3]. Lawrence Berkeley National Laboratory (LBNL) projects data-center consumption to reach 649 TWh by 2030, or 11.8% of projected US electricity use, with a plausible range of 521 to 843 TWh depending on the pace of AI adoption[3]. AI servers alone are expected to account for more than half of this total by 2030[3]. The Department of Energy's (DOE) resource adequacy modeling shows coincident peak load rising from 774 GW today to 889 GW by 2030, at an annual growth rate of 2.3%[4]. Excluding data centers, that rate falls to 1.1% per year[4], showing how much national resource adequacy planning now rests on a single customer segment.

This demand is also geographically concentrated, driven by structural factors such as land availability, cost-competitive access to transmission and generation, and state-level incentives. Northern Virginia alone hosts over 5 GW[7], 13% of global operational data-center capacity[8]. Dominion Energy reported that data centers accounted for about 28% of its 2025 electricity sales[9]. Texas is the second-largest market, and new development is moving into Ohio, Iowa, and Indiana as established locations run into generation and interconnection constraints.

New generation capacity is being added under compressed timelines. Solar, wind, and battery storage accounted for about 26% of the total installed capacity in 2025[1]. Their combined share is projected to reach 46% by 2035[2]. The projected renewable growth is subject to a significant policy caveat. The July 2025 One Big Beautiful Bill Act provided a longer runway for storage, nuclear, and geothermal, while narrowing the runway for solar and wind tax credits. Nuclear is a long-lead option but carries strong current policy backing following the May 2025 executive order targeting a quadrupling of nuclear capacity by 2050[10]. Several utilities have begun incorporating small modular reactors (SMRs) into long-term plans. Natural gas is re-emerging as a principal source of firm capacity to support data-center load. Utility integrated resource plans now call for about 84 GW of new gas-based capacity through 2035, roughly 32 GW more than expected two years ago[7].

Figure 3: Growth in US Consumption, Clean Power, and Battery Capacity



Source: Energy Information Administration (EIA), Form EIA-860, EIA Annual Energy Outlook (2026)

A comparable shift is underway at the periphery of the grid. Distributed energy resources (DERs) such as rooftop solar and battery storage are presenting new challenges for grid operators. Small-scale solar generation is projected to rise from about 93 TWh in 2025 to roughly 114 TWh by 2027, about 11% a year[11], with a higher share of generation in states such as California, Texas, Florida, and Nevada. Each new rooftop system or battery installation introduces two-way power flow into distribution networks that were built to deliver power in one direction only. Grid operators now need to manage voltage, local congestion, and protection coordination far more actively than before.

Exposure to physical, cyber, and climate risk is increasing. Cyberattacks on US utilities reached 1,162 in 2024, up 70% year-on-year[12]. North American Electric Reliability Corporation (NERC) recorded more than 3,500 physical security breaches in 2025[13]. About 60 new potentially vulnerable points are added to the grid each day as DERs proliferate[12].

Risks related to extreme weather are becoming equally significant. California's Public Safety Power Shutoffs illustrate the trade-off between wildfire mitigation and reliable supply. Following severe windstorms in January 2025, Southern California Edison (SCE) carried out planned outages, prompting regulators to raise concerns over their scale and customer impact. NERC finalized new transmission planning standards for extreme heat and cold in 2024, requiring utilities to develop a corrective action plan based on an evaluation of grid stability under benchmark extreme weather parameters, and its 2025 Summer Reliability Assessment identified elevated wildfire and hurricane risk from the West Coast to the Gulf Coast. Massachusetts Institute of Technology (MIT) research found that power systems planned using historical weather patterns could face up to five times more energy shortfalls by 2050[14]. This indicates that forward-looking climate scenarios, not historical records alone, must inform future transmission planning. Federal Energy Regulatory Commission (FERC) Order 881 (December 2021) reflects this shift, requiring transmission owners to rate transmission lines against forecast temperatures rather than fixed seasonal assumptions. ■

CHALLENGES FACING THE US GRID

3

The developments described in Chapter 2 are placing new demands on the grid's physical capacity and operating requirements, simultaneously affecting five key domains: network capacity, real-time stability, resource adequacy, flexibility, and resilience.

3.1 Network Capacity

The US transmission network is not expanding fast enough to match new generation, demand, and power flow patterns. Congestion costs are estimated at $12 billion for 2024[5], occurring mostly when net load is high, temperatures are low, and the system leans heavily on intermittent generation. Congestion also strands renewable energy. California curtailed 3.4 TWh of utility-scale wind and solar in 2024, up 29% from 2023, with solar accounting for 93%[15]. Texas curtailed more than 8 TWh of wind and solar in 2024[16], about 22% of the region's renewable output.

Aging infrastructure amplifies this constraint. About 70% of transmission lines are more than 25 years old[17]. The American Society of Civil Engineers (ASCE) gave the US energy sector a D+ in its 2025 Infrastructure Report Card, citing aging assets, underinvestment, and deferred maintenance[18]. The Brattle Group estimates that about 4,000 circuit-miles of transmission need replacing each year, requiring roughly $10 billion in annual investment[5].

Limited network capacity, combined with outdated interconnection frameworks and an increasing number of applications, has contributed to lengthening interconnection queues. As of end-2025, about 1,312 GW of generation and 749 GW of storage capacity were seeking interconnection to the grid, 1.5 times the roughly 1,374 GW of total installed generation capacity[19]. Timelines have lengthened sharply: the median project reaching commercial operation in 2024 had spent 55 months in the queue, up from 36 months for projects completed in 2015[20]. FERC has pointed to speculative applications and weak readiness requirements as the main causes.

Figure 4: Challenges Facing the US Grid

Network Capacity
$12 billion congestion cost in 2024
2,061 GW generation & storage interconnection queue (end of 2025)

Real-Time Stability
3,800 MW of Northern Virginia data-center load disconnected in July 2026

Resource Adequacy
13 of 23 NERC regions at elevated risk

Flexibility
70 GW Potential flexible load from data centers

Resilience
1,162 cyber attacks (2024)
3,500 physical incidents (2025)

3.2 Real-Time Stability

For most of the US grid's history, real-time frequency stability came built in. Large synchronous generators (coal, gas, nuclear, and hydro) rotated in step with the grid's 60 Hz frequency, and their combined mass gave operators several seconds to respond to any sudden imbalance. As these units retire and are replaced with renewable resources connected through power electronics, that inertia is declining. NERC's 2025 Long-Term Reliability Assessment (LTRA) finds that the current fleet can still meet frequency stability requirements through 2027, but this capability weakens afterward without intervention.

Inverter-based resources have also shown weak behavior during disturbances. NERC investigations have found some units reducing output, entering momentary cessation, or tripping offline exactly when the system needs support. FERC Order 901 directed NERC to develop new ride-through standards in response. FERC has since approved Reliability Standard PRC-029-1, with mandatory ride-through requirements effective August 2025.

Voltage stability faces a similar challenge. While reactive power was typically available as a by-product of synchronous generators, regulatory frameworks, grid codes, and market arrangements are necessary in grids dominated by inverter-based resources to ensure that reactive power services remain available.

Large loads such as data centers can also cause stability risks from the demand side. A voltage dip can activate backup generators, automatically disconnecting these facilities from the grid. If several facilities in one region respond to the same disturbance, hundreds of megawatts of load can disappear within seconds. A transmission fault in Northern Virginia in July 2024 caused about 60 data centers across 25 substations to disconnect and switch to backup power, removing roughly 1,500 MW of load within seconds[21]. More recently, a transmission line failure in Northern Virginia in July 2026 led to unexpected disconnection of 3.8 GW of data-center load from the grid, causing spikes in system frequency and voltage, prompting PJM to reconsider ride-through standards for rapidly growing computational loads[6].

3.3 Resource Adequacy

Stability challenges unfold in seconds; adequacy asks whether sufficient capacity will be available when demand arrives. NERC's 2025 LTRA projects summer peak demand rising by 224 GW over the next decade, 69% above the 132 GW projected a year earlier and the fastest growth rate NERC has recorded since 1995[22]. Data-center growth and electrification are the main drivers.

The same thermal retirements that reduce inertia also reduce firm capacity for peak demand, connecting directly to the adequacy challenge. Over the past year, fossil capacity fell by 21 GW while battery, wind, and solar capacity rose by 23 GW, a net addition that does not provide equivalent firm capacity during stressed times[22]. As a result, 13 of NERC's 23 assessment areas now face elevated resource adequacy risks over the next five years[22].

DOE's July 2025 Resource Adequacy Report identifies transmission expansion as key to improving reliability, allowing regions to share resources during peak demand. DOE is also building a uniform methodology for evaluating reserve margins, including accrediting generation based on historical performance rather than nameplate capacity. It has proposed a new reliability standard of no more than 2.4 hours of lost load per year and no more than 0.002% of annual energy unserved[4].

3.4 Flexibility

Flexibility is the ability to match supply and demand across timescales, from seconds to entire seasons. Wind and solar output depends on weather conditions, not on when demand peaks. Meeting this need requires resources that can ramp quickly, store energy, or shift consumption over time.

Greater interregional transmission capacity, allowing one region to draw on a neighbor's surplus during stress, could help, but remains limited across much of the US. Neighboring regions often have different weather, demand, and generation profiles that could allow them to support one another, but interregional transfer capability remains limited by underinvestment, fragmented planning, permitting hurdles, and cost-allocation issues.

Meanwhile, rising electric vehicle (EV) charging, heat pump adoption, and rooftop solar can add flexibility on the demand side. FERC Order 2222 requires grid operators to allow aggregated DERs (batteries, smart thermostats, EV chargers) to participate in wholesale energy, capacity, and ancillary service markets. Most utilities, however, are still building the market rules and metering needed to implement this. For example, while long-duration energy storage (LDES) can help address multi-day reliability and resource adequacy risks, current market structures were largely designed around shorter-duration storage technologies and do not yet fully compensate for the resilience and resource adequacy value provided by LDES assets.

Data centers pose the same flexibility challenge at a much larger scale. The International Energy Agency (IEA) finds that if US data centers reduce their demand for just 1% of operating hours, the grid could accommodate up to 70 GW of new capacity within the existing network, covering all colocation, service provider, and hyperscale additions[7].

3.5 Resilience

Extreme weather, cyberattacks, and physical threats are all growing and testing the grid's ability to withstand and recover from disruption, each exploiting the same aging, congested infrastructure.

Extreme weather: Winter Storm Uri in February 2021 left up to 4.5 million Texans without power after gas supply and generation equipment failed to withstand sustained sub-freezing temperatures[23]. Winter Storm Fern (January 2026) again tested the grid, pushing winter demand to some of the highest levels on record and requiring federal intervention across several regions.

Summer heat brings a different set of challenges. High temperatures raise cooling demand while reducing line capacity as conductors sag, and thermal plants see higher forced outages. NERC identifies extended heat waves as one of the top reasons behind elevated risk of unserved energy. In the Gulf Coast and Southeast, hurricanes remain the most significant recurring threat. IEA estimates that extreme weather caused $131 billion in grid and generation damage in the first half of 2025 alone[24]. DOE's Grid Resilience and Innovation Partnerships (GRIP) program directs $10.5 billion to interconnection, modernization, and resilience projects[25].

Cyber and physical security: NERC estimates roughly 60 new vulnerable points are added to the grid daily as decentralization and modernization continue[12]. Smart meters, automated substations, and distributed control platforms are needed for a more flexible grid, but each expands the attack surface. A successful attack can cause wider equipment failure rather than simply disrupt data. The 2024 NERC and FERC updates to Critical Infrastructure Protection (CIP) standards have strengthened access controls and supply chain requirements.

Physical attacks are also rising. NERC recorded more than 3,500 physical security incidents in 2025, many resulting in operational disruptions[13]. Because a small number of large substations and transmission corridors carry a disproportionate share of power flow, a targeted attack can have outsized consequences. Physical security remains largely a utility responsibility, with less consistent national standards than cybersecurity.

The challenges described in this chapter are not separate problems with separate solutions. They are connected demands on a system that must deliver reliable power while building a different grid tomorrow. This will require sustained investment, regulatory reform, technology deployment, and changes to how the grid operates. ■

INFRASTRUCTURE EXPANSION AND INVESTMENT NEEDS

4

Between 2016 and 2024, the US added, upgraded, or rebuilt about 85,000 circuit-miles of transmission at 69 kV and above, roughly 16% of today's network[5]. Most of this infrastructure was for maintaining reliability (38%), followed by replacing aging assets (20%)[5]. The US spent an average of about $13 billion a year on regional and interregional transmission over this period[5], roughly $117 billion in total.

This investment is significant, but not sufficient. The US is now trying to correct decades of underinvestment within a much shorter timeframe.

NERC data shows about 30,764 circuit-miles of transmission planned through 2038, split between 21,709 miles of new lines and 9,055 miles of upgrades at 100 kV and above[26]. A large part of the existing network is already running near its limit, and reinforcing it is often the precondition for new connections. According to the Edison Electric Institute (EEI), investor-owned utilities are expected to invest approximately $1.36 trillion between 2026 and 2030[27]. If transmission maintains its historical share of around 20% of total capital expenditure, this will translate to about $272 billion in transmission investment over the period[27].

Every major regional grid operator has its own expansion plan underway, most of it reflecting the need to serve rising data-center demand. Other drivers include replacing aging infrastructure, connecting new generation, and meeting resource adequacy requirements.

Interregional transmission ties offer a strong improvement opportunity for the US grid. DOE's National Transmission Planning Study (NTPS) estimates this capacity must grow 1.9 to 3.5 times 2020 levels by 2050[28]. FERC Order 1920 (2024) now requires transmission providers to plan regionally and account for these interregional needs.

Cross-border interconnection with Canada also plays a role in meeting resource adequacy needs, particularly on the Northeast corridor. Recent additions, including the Champlain Hudson Power Express[29] and the New England Clean Energy Connect[30], have expanded import capacity into New England and New York by more than 2,450 MW combined. ■

Figure 5: Proposed Spending Under Key Regional Transmission Plans

RTO / ISO	Proposed Spending
ERCOT Electric Reliability Council of Texas	**$12.0 billion** 2024 Regional Transmission Plan *by 2030*
PJM PJM Interconnection	**$11.8 billion** 2025 RTEP, Window 1 *by 2032*
MISO Midcontinent ISO	**$10.3 billion** LRTP Tranche 1 *completion from 2028 through 2030* **$30 billion** Tranche 2.1 and JTIQ portfolios *later portfolios*
SPP Southwest Power Pool	**$8.6 billion** 2025 Integrated Transmission Plan *by 2035*
CAISO California ISO	**$4.8 billion** 2024–25 Transmission Plan *in the next 10-15 years* **$45.8–63.2 billion** 20-Year Transmission Outlook *to 2045*

Source: Individual RTO/ISO transmission plans, DOE National Transmission Needs Study (Draft, July 2026)

THE PATH TO DELIVERY: KEY ENABLERS

5

The investment requirements described in Chapter 4 can only be realized if the right delivery conditions are in place. These include coordinated, forward-looking planning; technology deployment at scale; a supply chain able to keep pace with equipment demand; and policy and market design that translates system needs into clear investment signals.

5.1 Planning for a Coordinated Grid

Long-term, holistic, and operationally aware planning: US transmission planning has historically been short-term and siloed, with utilities meeting near-term reliability criteria within their own geographic footprint rather than weighing regional needs 15–20 years out against demand growth, retirements, and electrification.

This is changing. FERC Order 1920 (May 2024) requires transmission providers to conduct long-term regional planning over a 20-year horizon, using multiple scenarios, and to evaluate projects against a broader set of benefits, including congestion relief and economic value, rather than reliability alone[31]. Seven overlapping, differently governed regions each run their own long-term processes, and interregional coordination happens through both formal and informal arrangements. MISO and SPP run a Joint Targeted Interconnection Queue across their shared areas; CAISO, WestConnect, and NorthernGrid conduct a biennial review of cost allocation for Western Interconnection projects; and New York Independent System Operator (NYISO), ISO-NE, and PJM coordinate through their Interregional Planning Stakeholder Advisory Committee to address cross-border system needs. The DOE's National Transmission Planning Study and National Transmission Needs Study identify where interregional transfer capacity would deliver the greatest benefit. However, neither is binding. They inform National Interest Electric Transmission Corridor (NIETC) designations and funding programs rather than compelling regional planners to act.

Planning should also reflect operational requirements of the evolving grid. FERC Order 1920's benefit test evaluates cost savings and congestion relief, but it does not require planners to size transmission against inertia shortfalls, voltage stability margins, or inverter ride-through performance. That work happens separately, through NERC reliability standards and FERC Order 901, rather than inside the regional planning process itself.

Faster permitting: Permitting, not planning, causes the greatest delays in US transmission timelines. Niskanen Center analysis of 2010–2020 data shows federal permitting timelines for interregional transmission lines spanned up to 11 years, averaging 4.3 years[32]. This process is driven by state-by-state fragmentation requiring separate environmental reviews, commission approvals, and eminent domain proceedings for each state a project crosses.

DOE's Coordinated Interagency Transmission Authorizations and Permits (CITAP) program establishes DOE as the lead federal agency responsible for consolidating and accelerating federal environmental reviews for qualifying interstate lines (230 kV and above, or otherwise nationally significant), running a structured pre-application process followed by a binding two-year federal review clock, with a presidential appeal mechanism if an agency misses its deadline. Separately, the Standardizing Permitting and Expediting Economic Development (SPEED) Act, passed by the House in December 2025, would narrow NEPA reviews to reasonably foreseeable effects, impose a 150-day statute of limitations on legal challenges, and limit agencies' ability to revoke issued permits. It has not yet cleared the Senate.

Faster interconnection: Connection queue speed is also important. FERC Order 2023 replaced the "first-come, first-served" model with a "first-ready, first-served" cluster study process. It requires generators to post study and commercial readiness deposits and submit study requests in batches. It also enforces a 150-day timeline with penalties for missed deadlines[33].

Large loads had no equivalent process until recently. In October 2025, DOE directed FERC to consider rules for connecting loads above 20 MW to the interstate transmission system, a matter previously left to states[34]. In June 2026, FERC issued Show Cause Orders to six regional grid operators, requiring each to justify or reform tariff provisions covering large-load study processes, cost allocation, and co-location with generation[35].

Anticipatory investment: Interconnection in the US remains reactive, triggered largely by generator or load requests rather than by forward build-out ahead of demand. FERC Order 1920's scenario planning identifies where capacity will likely be needed but does not authorize or fund construction before a specific project materializes.

New large loads can be built in one to two years; new transmission takes six to ten years. While forecasting future load and generation locations remains uncertain, the cost of not building the grid is higher than the cost of over-investment. Anticipatory investment in network capacity can address the infrastructure lag and the interconnection backlogs. Grid-enhancing technologies (GETs) partly compensate, since they can be deployed in months using existing rights-of-way. DOE's Speed to Power through Accelerated Reconductoring and other Key Advanced Transmission Technology Upgrades (SPARK) program is built around that speed advantage. But SPARK upgrades existing infrastructure rather than funding new capacity in advance.

5.2 Technologies for Increasing Grid Capacity and Managing Grid Complexity

5.2.1 Increasing Grid Capacity

GETs, including advanced conductors, dynamic line rating (DLR), advanced power flow controllers (APFCs), and Transmission Topology Optimization (TTO), are one of the fastest available routes to enhance grid capacity. LBNL-reviewed research finds that deploying advanced conductors across the US system could quadruple projected capacity expansion by 2035 and save $85 billion relative to business

Figure 6: Illustrative Technologies to Increase Capacity, Manage Complexity, and Enhance Resilience

Increase Capacity

- Advanced Conductors
- DLR
- HVDC
- Transmission Topology Optimization

Manage Complexity

- Grid-Forming Inverters
- STATCOM / FACTS
- BESS
- PMUs & Digital Twins

Enhance Resilience

- Climate Hardening Equipment
- Wildfire Mitigation
- Cybersecurity
- Weather Forecasting

as usual[36]. DLR replaces conservative static ratings with real-time sensor-based assessments of actual line capacity. APFCs and TTO allow operators to actively redirect power from underused paths. DOE estimates these technologies could together add roughly 40–110 GW of new transmission capacity without new lines[37], helping bridge the gap while new infrastructure is being developed. While GETs are not a substitute for new transmission infrastructure, they can improve the utilization of the existing grid.

While GETs could increase the capacity of the existing infrastructure, high-voltage direct current (HVDC) technology provides a complementary pathway by enabling the development of new, high-capacity transmission corridors across regions. It requires new infrastructure but is highly efficient in moving large amounts of power over long distances. NERC's Interregional Transfer Capability Study found that more transfer capability between regions improves reliability, allowing surplus power in one region to support another under stress. Multi-terminal HVDC, connecting three or more grid nodes, could build the meshed backbone the US lacks. DOE's 2024 NTPS identified multi-terminal HVDC as one of the three frameworks capable of meeting the most ambitious demand and clean energy scenarios[28].

5.2.2 Managing Grid Complexity

A range of commercially available technologies help operators manage rising system complexity, largely by using advanced power electronics and digital controls to deliver functions that conventional generators used to provide.

Grid-forming inverters can establish and regulate voltage and frequency directly, rather than synchronizing to an existing signal as conventional grid-following inverters do, supporting stability in weaker, inverter-heavy grids. This aligns with FERC Order 901's mandatory reliability standards for inverter-based resource performance during disturbances. DOE is supporting demonstration projects with utilities and manufacturers to validate the technology for the bulk power system.

Synchronous condensers, rotating machines providing inertia and reactive power without generating electricity, are being deployed as coal and gas plants retire. Some utilities are converting retiring fossil units into condensers by removing the turbine and repurposing the generator, a cheaper option that reuses existing interconnections. ERCOT and MISO, both facing steep near-term inertia decline, have seen growing interest in conversions to preserve local voltage support.

Flexible AC Transmission System (FACTS) devices, including Static VAR Compensators (SVCs) and Static Synchronous Compensators (STATCOMs), respond within milliseconds to voltage disturbances, providing fast reactive power support at transmission and distribution levels. STATCOMs paired with supercapacitors (E-STATCOMs) can also supply active power, supporting frequency response, disturbance recovery, and, in some designs, black-start capability. Modern STATCOMs can also run grid-forming control, letting them set voltage references and damp oscillations, valuable in weak, high-renewable grids where voltage conditions can deteriorate quickly. FACTS devices install faster than new transmission lines, making them a near-term fix for local voltage and stability challenges while larger upgrades are built.

Battery energy storage systems (BESS) support flexibility, renewable integration, and reliability. It is the fastest-growing category of new US capacity, rising from roughly 1.5 GW in 2020 to more than 44 GW by the end of 2025, and is expected to reach about 100 GW by 2035[2]. Beyond shifting energy across hours, batteries provide frequency regulation and other services normally supplied by spinning reserve. With grid-forming controls, BESS can also set voltage and frequency directly, supporting weak or low-inertia grids and enabling black-start recovery. Most BESS deployed today are short-duration (four hours or less), effective for daily balancing but not for multi-day periods of low wind and solar. LDES is still needed to cover the multi-day resource adequacy risk NERC flags for winter storms and extended heat.

Effective operation of a power-electronics-based grid depends on accurate, real-time visibility of network conditions. Phasor Measurement Units (PMUs) deliver measurements 30 to 120 times a second, against 2–4 seconds for conventional monitoring, giving operators real-time visibility of voltage angles, frequency deviations, and power flow before a disturbance propagates, relevant as large, concentrated loads create rapid, localized demand shifts[38]. Recent US developments indicate that the Wide Area Monitoring System (WAMS) is evolving from a situational awareness tool into a real-time stability monitoring platform. ERCOT and the Electric Power Research Institute (EPRI) have demonstrated a proof of concept that uses existing PMU infrastructure to estimate system strength and inertia in real time[39]. Meanwhile, Novel Applications for Synchronized Power Instrumentation (NASPI), a joint initiative between DOE and EPRI, is developing industry guidance for operational monitoring of oscillations, voltage stability, system strength and inertia to support reliable operation of inverter-dominated power systems. The initiative also builds on a mature synchrophasor infrastructure already in place across the country. More than 2,500 PMUs are already deployed across the three major US interconnections[40], and current efforts focus on extracting greater operational value from this existing network through advanced analytics, AI-enabled applications, and real-time stability assessment.

Digitalization is also expanding. Digital twins improve transmission planning, asset management, and grid resilience. American Electric Power (AEP) is developing a digital twin of its entire transmission network[41], and the New York Power Authority (NYPA) is building the first digital twin of New York State's electric grid through its AGILe laboratory to test new technologies before field deployment[42].

Utilities are also deploying advanced digital control platforms. Energy Management Systems (EMS) support real-time monitoring and generation dispatch. Advanced Distribution Management Systems (ADMS) improve reliability through outage management and fault restoration. Distributed Energy Resource Management Systems (DERMS) coordinate DERs to provide voltage support and peak-shaving services. SCE, Pacific Gas and Electric (PG&E), Duke Energy, Xcel Energy, and many others have deployed these platforms to increase DER hosting capacity and defer grid reinforcements.

5.2.3 Enhancing Cyber and Extreme Weather Resilience

Expanding transmission capacity alone is not enough if the grid cannot withstand frequent extreme weather and cyber threats. Weather-resilient conductors, strategic undergrounding of vulnerable overhead lines, and flood- and fire-resilient substation designs reduce exposure to climate hazards. Florida Power & Light (FPL) has hardened about 85% of its main lines, including undergrounding 45% of its distribution network through its Storm Secure Underground Program[43]. PG&E and SCE committed around $23.8 billion to wildfire mitigation over 2023–2025[44]. This includes PG&E's plan to underground 10,000 miles of lines in high-fire-risk areas[45].

Meanwhile, being able to isolate affected parts of the network and restore supply using local generation, battery storage, and grid-forming inverters limits customer interruptions and speeds up recovery after major disturbances. Digital twins help by simulating how infrastructure will perform under future climate scenarios so operators can prioritize investment based on projected risk rather than past events.

Cybersecurity requirements have also evolved. NERC's CIP standards establish mandatory cybersecurity requirements for the bulk power system, with compliance subject to FERC oversight. In June 2025, FERC approved Reliability Standard CIP-015-1 through Order No. 907, requiring internal network security monitoring within electronic security perimeters to detect malicious activity after an attacker gains access; it took effect in September 2025, with implementation phased through 2028–2030. FERC has directed NERC to develop further requirements for access control systems outside the perimeter.

5.3 Strengthening the Supply Chain

Physical infrastructure investment and technology deployment are both constrained by equipment availability. Transformers are the most acute near-term constraint. Large power transformer procurement has become increasingly constrained, with typical lead times of around 36 months and maximum lead times of up to 60 months[46]. HVDC cables, converter stations, and GIS switchgear face similar constraints. The US relies heavily on imports, and a transformer failure at a critical substation can cause an outage of a year or more without a spare. Supply chain resilience is now as important as any other enabler, particularly as industrial, economic, and geopolitical changes increase pressure on already concentrated global supply chains. DOE has identified grid equipment shortages as a national security concern and launched procurement support initiatives, though the gap between demand and domestic capacity remains wide.

Expanding domestic manufacturing and harmonizing the technical specifications of major grid equipment and tools are two ways to strengthen supply chains. A Presidential Determination issued in April 2026 designated grid infrastructure supply chains, including transformers, high-voltage circuit breakers, power control electronics, and electrical core steel, as essential to national defense. It authorized DOE to make direct purchases and purchase commitments to expand capacity and provide financial support for the development of production capabilities.

Harmonized technical specifications enable replicability between projects, allow for transfer of learnings, reduce design time, and result in more efficient manufacturing and construction, ultimately lowering project costs and timescales. Industry and DOE efforts to move toward more standardized transformer designs aim to shorten delivery times. Harmonization can also help unlock benefits of pooled procurement as now seen in Europe. SSEN Transmission and National Grid are jointly procuring standardized ±525 kV HVDC converter technology for some of their projects, and German TSOs have partnered with Siemens Energy, Hitachi Energy, and GE Vernova to develop common technical specifications for multi-terminal HVDC hubs.

Common technical standards also help protect the grid against cyber and climate risks. International standards, such as IEC 61850 for digital substations and ISO/IEC 27001 for information security, define how control systems and communications should be secured. As mentioned above, NERC's CIP standards set mandatory cybersecurity requirements for the bulk power system, with compliance overseen by FERC. Climate and resilience standards, including ISO 14090 (climate change adaptation), ISO 14091 (climate risk and vulnerability assessment), and IEC TR 63515 (power system resilience), are also being harmonized internationally.

5.4 Advancing Policy, Regulatory, and Market Reforms

Policy and regulation guide the planning, technology, and supply chain investments described above. In the US, this task is complicated by a system where federal, state, and regional authorities each hold distinct and overlapping responsibilities.

5.4.1 Policy Direction

Regulatory reform works best against a stable policy backdrop, and that backdrop has recently shifted more than the underlying technical reforms have. Executive Order 14156 declared a national energy emergency prioritizing dispatchable generation. A companion order, Unleashing American Energy, directed agencies to remove regulatory barriers to domestic energy production. The ability of the grid to support AI-driven digital and economic growth will depend on how effectively planning, interconnection, and permitting processes can accommodate rapidly growing demand.

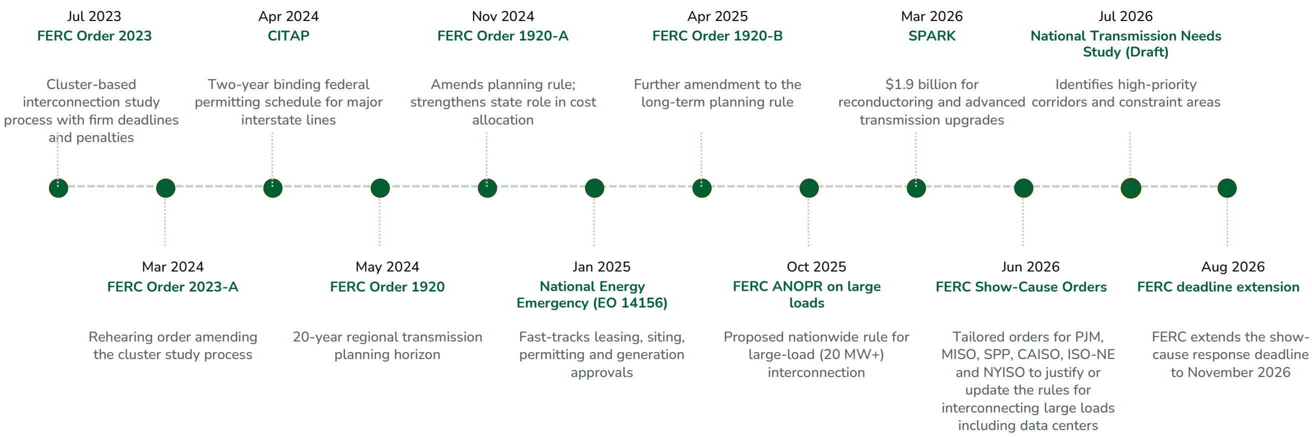
These priorities carry through into DOE's delivery-focused programs. CITAP aims to reduce permitting timelines for qualifying interstate transmission projects, while the National Transmission Needs

Study identifies where the grid is most constrained and where new capacity would deliver the greatest benefit. DOE's $1.9 billion SPARK program, which is the third round of funding under GRIP[25], funds the faster deployment of GETs to add capacity on existing infrastructure. None of these replaces large-scale transmission buildout, but together they form a parallel track that can deliver capacity while longer-horizon projects move through planning and construction.

service markets. ERCOT's energy-only design gives consumers particularly strong price signals to shift load. EPRI's DCFlex initiative, with more than 60 companies, is demonstrating that large loads can be managed as flexible grid assets that modulate power draw in response to real-time grid signals.

Battery storage already participates in these markets. FERC Order 841 (2018) required RTOs and ISOs to revise their tariffs for electric storage resources to participate directly in wholesale capacity, energy,

Figure 7: Key Grid-Related Federal Policy and Regulatory Frameworks



5.4.2 Market Reforms

Market rules and grid codes largely determine the pace of technology deployment and infrastructure investment. Demand itself is being drawn into grid operations as a flexibility resource, and wholesale market design and technical interconnection standards need to evolve to reflect this.

Demand response and flexibility: Shifting consumption away from peak periods can reduce the transmission capacity otherwise needed to serve growing loads continuously. PJM, ERCOT, MISO, and CAISO have established frameworks that allow demand-response and flexible-load resources to participate in electricity markets. Large consumers can reduce or shift consumption in response to grid conditions and, in some cases, earn revenue through participation in capacity, energy, and ancillary

and ancillary service markets, recognizing that storage can function as both generation and load. FERC Order 2222 (2020) extended a similar principle to smaller, distributed resources and required RTOs and ISOs to open wholesale markets to aggregations of DERs, allowing small rooftop solar, batteries, EVs, and demand response to participate when pooled by an aggregator. However, implementation remains uneven even after more than five years. Some regions have approved compliance filings and begun onboarding aggregations; others are still working through market design.

Meanwhile, Time-of-Use (TOU) pricing, which charges different rates depending on when electricity is consumed rather than a flat rate throughout the day, is being rolled out in many states. By mid-2026, roughly a dozen states had some form of mandatory or default residential TOU

Policy Priorities for a Coordinated Grid

- Translate system needs into economic signals. Technical requirements alone do not guarantee that grid services get delivered. Market mechanisms, such as ancillary services, capacity markets, and flexibility procurement, convert operational needs into price signals for asset owners.
- Harmonize across jurisdictions. Differences in interconnection rules, cost allocation, and net metering treatment across states and RTOs raise participation costs and slow interregional projects.
- Coordinate demand-side flexibility. As large loads and DERs grow, wholesale markets and utility tariffs need consistent rules for how flexibility is compensated and dispatched.
- Keep pace with a changing generation mix. Rising shares of inverter-based resources and large, fast-growing loads are changing system characteristics faster than some standards and market rules can adjust to reflect them.

pricing, with peak rates commonly two to three times off-peak rates[47].

Grid codes and interconnection standards: Grid codes establish the technical rules generators, storage, and other resources must meet to connect to and operate on the power system, covering synchronization, voltage regulation, frequency response, and behavior during disturbances. As the generation mix shifts from large synchronous generators to inverter-based resources, these rules have evolved. Many resources are now expected to stay connected during disturbances and support system stability, rather than disconnect.

Two standards now cover this shift at different points on the grid. IEEE Standard 1547-2018 sets the principal technical requirements for connecting DERs to distribution networks, with IEEE 1547.1-2020 defining compliance testing and UL 1741 (2021) setting product certification. IEEE 1547-2018 introduced mandatory voltage and frequency support, updated anti-islanding rules, fault ride-through requirements, and communications capabilities, allowing DERs to stay connected and support the grid during disturbances. Adoption speed varies by state, and because distribution interconnection is largely a state matter, implementation depends on state regulators even though the standard itself is national.

At the transmission level, IEEE 2800-2022 sets equivalent requirements for utility-scale, inverter-based resources, wind, solar, and storage, connecting directly to the bulk power system. It specifies ride-through, voltage regulation, and ramp-rate requirements for these larger installations, complementing FERC Order 901's reliability standards for inverter-based resource performance during disturbances.

IEEE 1547 and 2800 focus on the technical requirements for connecting resources to the grid. DOE's Office of Electricity published a distribution grid code framework in November 2023, which describes how requirements evolve as DERs expand, and calls for closer coordination between utilities, system operators, and market participants once DERs support both distribution and transmission operations. ■

CONCLUSION

6

US electricity demand is growing rapidly, driven primarily by data centers, AI adoption, and wider electrification across the economy. While generation capacity continues to expand, the transmission and distribution capacity has not kept pace. As a result, the grid has become the principal constraint on connecting new generation, serving new demand, and maintaining reliable system operation.

Closing the gap between demand and network capacity requires progress across four areas. Transmission planning needs to look further ahead, strengthen coordination across regions, and anticipate future demand rather than respond only to individual connection requests. Planning should also incorporate operational requirements from the outset, ensuring that network expansion supports system security, flexibility, and reliability under real operating conditions.

Commercially proven technologies, including advanced conductors, dynamic line rating, grid-forming inverters, HVDC, and battery storage, should be deployed at scale to increase network capacity and improve system performance. Supply chain constraints, particularly for transformers, require sustained investment in domestic manufacturing capacity, workforce capability, and common technical standards. Market design and grid codes should continue to reward the services provided by storage, flexible demand, and distributed energy resources, enabling them to contribute fully to system operation.

The US thus needs a faster pace of coordinated delivery, across planning, technology, supply chain, and policy, to match the scale of demand already arriving. ■

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