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MEETING RISING U.S. ELECTRICITY DEMAND FROM AI AND DATA CENTERS:

AN INTEGRATED TECHNICAL AND POLICY PERSPECTIVE

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EXECUTIVE SUMMARY

The rapid expansion of artificial intelligence (AI) data centers, electrified transportation, and strategic reshored manufacturing are increasing the demand for electricity at rates that could outpace current supply. Data centers account for nearly half of five-year projected load growth (Abdelhady et al., 2025; Deese & Hansmann, 2025). An ability to meet rising demand threatens U.S. economic competitiveness, resilience, and national security by straining transmission infrastructure, increasing prices, and increasing the risk of power failures. Political fragmentation and outdated regulatory incentives leave nearly half of existing capacity underemployed. Interstate disputes, such as efforts by North Dakota and allied states to block Midwestern transmission projects, reflect a broader structural failure (Orenstein, 2025). Without urgent reform, the United States will be unable to support the next generation of AI infrastructure, industrial investment, and national defense capabilities. This white paper examines the causes of the emerging electricity crisis, analyzes the institutional and market barriers to grid modernization, and offers several recommendations for the federal government, state governments, utilities, and large electricity users.

MOTIVATION

After nearly two decades of flat electricity consumption, electricity use is now rising at the fastest pace since World War II. Transportation electrification, heating, the expansion of semiconductor manufacturing and other critical reshored manufacturing supply chains, and, most significantly, the explosive growth of energy-intensive artificial intelligence data centers (Abdelhady et al., 2025; Deese & Hansmann, 2025) all contribute to this rise. This trend suggests energy expansion is the new reality. New renewable sources are being added to the energy mix but are not displacing traditional fossil fuels as overall demand grows faster than any single source can supply. The North American Electric Reliability Corporation projects that national peak demand will increase by 18 percent over the next decade (North American Electric Reliability Corporation (NERC), 2025).

Recent analysis shows that data centers account for 44 percent of projected U.S. electricity load growth through 2028. Most of the increase comes from AI-related workloads. In Texas and the Midwest, interconnection requests from hyperscale data centers have expanded from 2.6 gigawatts in 2022 to a projected 173 gigawatts by 2030, which far exceeds existing grid capacity (Abdelhady et al., 2025). Major technology company commitments include Meta's multiple gigawatt-scale facilities in the Southeast and Midwest, Amazon's eight gigawatts for data center expansion in Virginia alone, and Microsoft's ten gigawatts for AI infrastructure (Casey & Saul, 2024; Riley, 2025).

Political and structural obstacles undermine attempts to meet rising demand. The Minnesota Star Tribune recently reported that North Dakota, Montana, and several southern states moved to block a $22 billion Midwestern transmission expansion that Minnesota argues is essential to meet surging demand from data centers and the retirement of coal plants (Orenstein, 2025). Illustrating the risks from an inability to cooperate, Minnesota regulators warn that obstructing this project will not only jeopardize grid reliability but actively weaken economic growth in the region. This domestic gridlock contrasts sharply against China's aggressive infrastructure deployment. Between 2020 and 2024, China added more than 300 gigawatts of grid capacity and constructed over 35,000 miles of ultra-high-voltage transmission lines (International Energy Agency (IEA), 2024). The inability to expand the grid at comparable speed threatens the U.S. competitive position in semiconductors, advanced manufacturing, and artificial intelligence.

Political challenges are compounded by structural inefficiencies. Emerging studies from the Department of Energy and Idaho National Laboratory demonstrate that the U.S. electric grid is undergoing stresses from structural forces that extend beyond historical fluctuations (Xue et al., 2022). Roughly half of the nation's generation and transmission capacity sits idle at any given moment because the grid was engineered not for cost-effective usage but for rare moments of peak stress (Deese & Hansmann, 2025). Instead of optimizing how electricity moves, the system continues to prioritize building new infrastructure under regulatory frameworks that reward capital deployment rather than performance or efficiency. This misalignment of incentives has resulted in escalating costs for consumers. Retail electricity prices in 2025 have risen nearly twice as fast as general inflation. Reliability has also fallen—outages have increased by 60 percent over the past decade (Deese & Hansmann, 2025).

This white paper presents an overview of the leading challenges in the current state of the U.S. power grid, the barriers preventing the United States from overcoming these challenges, and some potential policy solutions that include suggestions for the most productive areas for future research. Taken together, we argue that the U.S. electric grid is no longer facing isolated operational challenges but systemic stresses that threaten the nation's economic competitiveness, resilience, and energy security. Without reforms by the federal government, state governments, utilities, and large users, the U.S. risks entering an era of chronic energy scarcity, stranded generation assets, and lost opportunities. Addressing these vulnerabilities critically supports U.S. strategic power, industrial success, and economic resilience in a multipolar and contested geopolitical landscape.

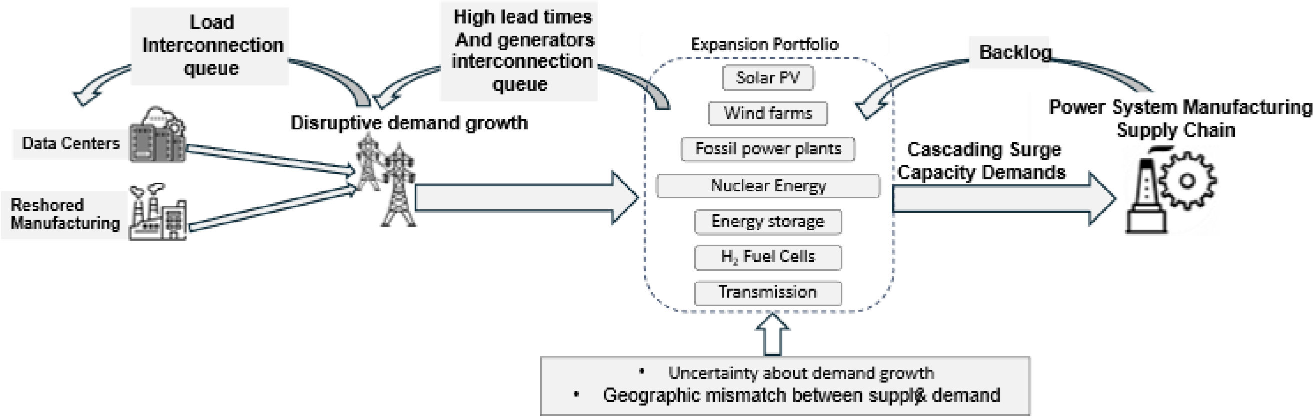
AN OVERVIEW OF THE U.S. ELECTRIC GRID

It goes without saying that electricity is a central determinant of regional prosperity and national strategic advantage. In the coming years, energy security and economic growth will be tied directly to electricity, not oil (Ip, 2025). The mismatch between rapidly escalating demand, stagnating supply, and persistent transmission capacity risks could hinder the adoption of AI, slow reshoring of critical manufacturing, and undermine next-gen energy evolution and climate adoption.

Figure 1 illustrates the converging pressures on the U.S. electric grid. On the demand side, explosive growth from AI data centers and reshored manufacturing is creating unprecedented interconnection requests. On the supply side, equipment manufacturing bottlenecks and multi-year lead times for critical components constrain the grid's ability to respond. In the middle, a portfolio of potential solutions, ranging from solar and wind to nuclear and storage, faces deployment delays due to supply chain capacity limits. Compounding these challenges are two fundamental uncertainties: the difficulty of forecasting rapid demand growth and the geographic mismatch between production and consumption.

For most of the postwar era, the U.S. electric grid was considered the most reliable in the world. This reliability, however, is gradually eroding (Larsen et al., 2015). Early national monitoring efforts established standardized

Figure 1: Grid Interconnection Delays and Cascading Supply Chain Effects



Source: Abdelhady et al., 2025

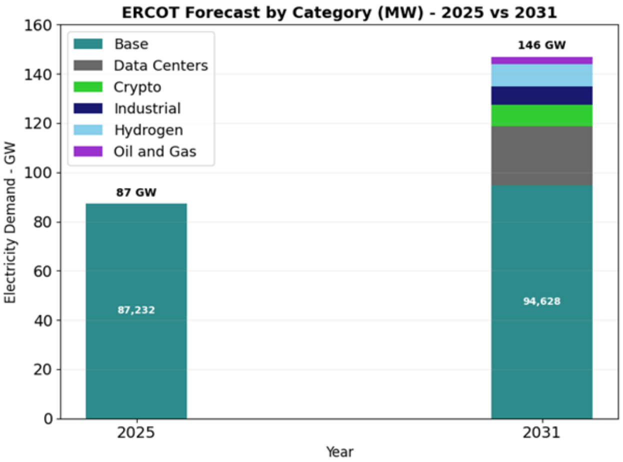
methods to track reliability through indices such as SAIDI and SAIFI (LaCommare & Eto, 2008). Subsequent reporting demonstrated that while average outage duration showed relative year-to-year stability, the distribution of events became more skewed (Eto et al., 2012). Major high-impact disruptions are becoming more common and the time trend of the annual average number of minutes of power interruptions over time is increasing (Larsen et al., 2016). As major storm events become more common (Larsen et al., 2020), building new forms of resilience into the electric grid becomes increasingly important. More than 90 percent of customer outages originate not from the bulk transmission system but from local distribution infrastructure (Eto et al., 2019). This implies that reliability challenges stem less from insufficient generation and more from aging poles, wires, and substations exposed to environmental stress. Meanwhile, (Sultan & Hilton, 2019) emphasizes that traditional reliability metrics that are designed to track average interruptions can underestimate systemic risk by failing to capture resilience.[1] It is increasingly appreciated that resilience must be measured not only in terms of restoration time but in adaptive capacity, redundancy, and flexibility across the system (Erenoğlu et al., 2024).

We suggest that the current state of the U.S. electric grid is best understood in three components: demand, supply, and transmission. We discuss the leading concerns of each of these three areas below.

Rising Demand

As noted above, several factors drive rising demand. Mirroring national trends, Figure 2 decomposes Electric Reliability Council of Texas (ERCOT) demand projections into the six main categories. Peak load is expected to surge from 87 GW in 2025 to 146 GW by 2031, a 68% increase. New data centers account for 24 GW of this growth, cryptocurrency mining adds 8.5 GW, industrial demand contributes 7.5 GW, and hydrogen and oil & gas operations add the remainder (ERCOT, 2025b).

Figure 2: ERCOT Peak Demand Forecast



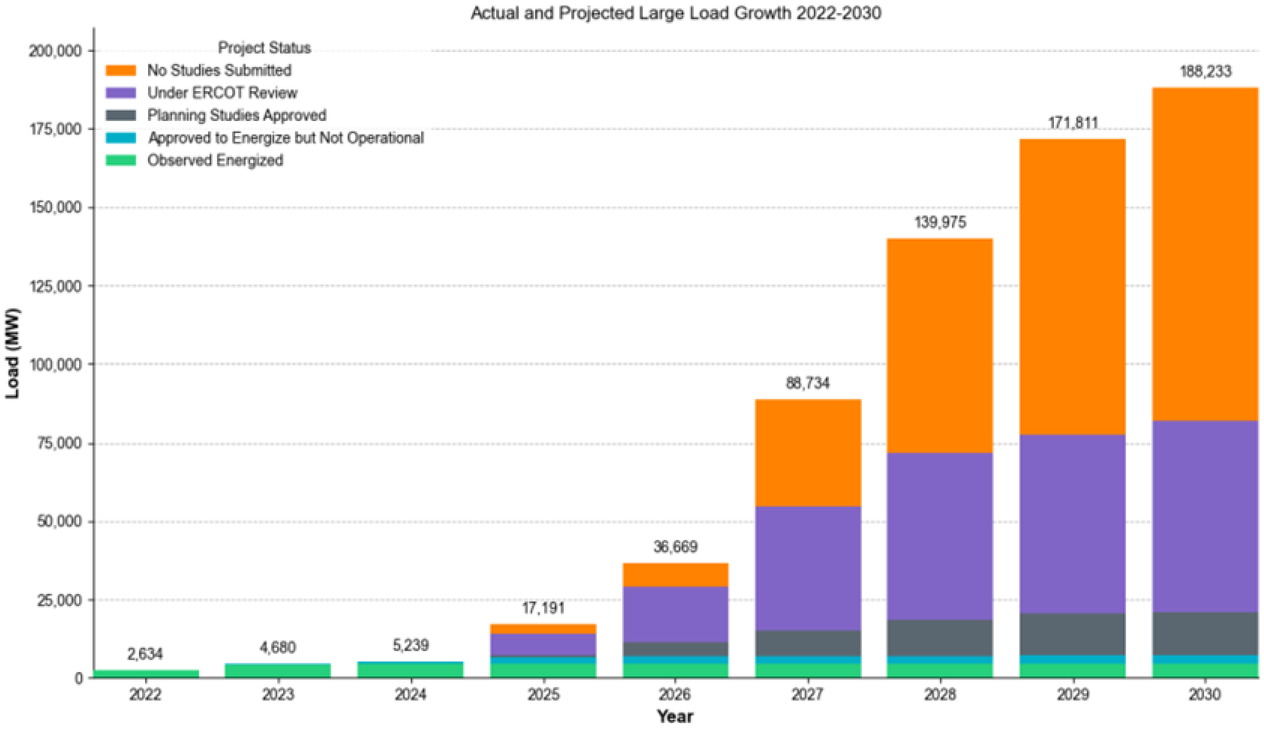
Source: Abdelhady et al., 2025; ERCOT, 2025b

It also goes without saying that Artificial intelligence (AI), large language models (LLMs), and advanced digital services are transforming economic activity. These technologies are computationally intensive and depend heavily on reliable and abundant electricity supplies. Data centers that host AI models operate at high utilization rates and require uninterrupted baseload power. Of the 44 percent projected increase in total U.S. electricity load growth between 2023 and 2028, AI-ready workloads are expected to comprise 35 to 70 percent of total data center consumption or incremental capacity by 2030, depending on scenario and methodology (Kamiya & Coroamă, 2025; McKinsey & Company, 2024; Walton, 2024).

Another important measure of expected growth is "Queue Growth."[2] Projects enter the interconnection queue as requests to connect to transmission infrastructure and receive approval to deliver or withdraw power. Figure 3 shows the ERCOT projection of large load queue growth.

ERCOT has also begun reporting a Large Load Interconnection Queue[3], ERCOT's May 2025 Capacity, Demand, and Reserves (CDR) report notes that while not all queued projects will reach commercial operation, the interconnection queue is a leading indicator of expected resource development and grid planning through 2030 (ERCOT, 2025c). External analyses of ERCOT's June 2025 queue show over 172 GW of proposed large-load demand expected by 2030, indicating that demand growth is accelerating nearly as fast as generation additions (Rwejuna & Bryant, 2025).

Figure 3: Actual and Projected Large Load Growth in ERCOT



Source: ERCOT, 2025a

Deep Uncertainty and Spillover Effects

A primary challenge for grid planners is that a significant portion of this projected demand is highly uncertain. This "phantom demand" refers to the large volume of load interconnection requests, particularly from data centers and cryptocurrency mining, which enter the queue but may ultimately be delayed or canceled.

This high degree of uncertainty creates a critical planning dilemma. If grid operators and utilities invest heavily in new generation and transmission to serve all queued projects, they risk creating stranded assets should that demand fail to materialize. Conversely, if they underestimate the load that will come online, the grid will be unable to meet actual demand, resulting in unreliability and increasing the risk of power failures.

This specific risk of unreliability (where grid capacity fails to keep pace with the explosive, real-world growth of AI demand) poses a direct threat to other critical sectors. Any resulting grid instability or blackouts would, in turn, undermine the resilience of the U.S. manufacturing supply chains. Supply chain resilience is a strategic priority for the nation with bipartisan support and a necessary condition for national manufacturing competitiveness in the 21st century, as supply chains need to compete within an increasingly volatile, uncertain, complex, and ambiguous (VUCA) landscape. In this context, grid instability emerges as another source of disruption (along with conflicts, trade wars, extreme weather events, strikes, etc.). Regulatory uncertainty also impacts manufacturing supply chains. Frameworks such as Texas Bill 6 (Texas Legislature, 2025), for instance, create significant demand-side risk by mandating that large loads curtail during periods of grid congestion. Hence, supply chains needs to be able to deal with (at additional cost) both before a disruption (proactive stage) and following disruption such as blackouts (respond and recovery) (Iakovou & White III, 2020).

Inefficient Supply

Over the past decade, the United States has added more nameplate generation capacity[4] than at any other time in its history. As of June 2025, ERCOT reported 2,054 active generation interconnection requests totaling 420,381 megawatts (MW) projected to come online through 2030 and beyond (ERCOT, 2025b).[5] These include approximately 162 GW of solar, 41 GW of wind, 178 GW of battery storage, and 35 GW of natural gas. By July 2025, the total had risen to 432,804 MW, reflecting sustained queue expansion and continued investor interest despite interconnection bottlenecks (ERCOT, 2025a). The amount of available, deliverable electricity supply, however, has remained effectively flat due to the retirement of firm generation, curtailment[6] of renewables, and grid congestion. According to the U.S. Energy Information Administration (EIA, 2024), net summer capacity increased by more than 150 gigawatts between 2014 and 2023, but dispatchable generation declined as 102 gigawatts of coal and 15 gigawatts of nuclear capacity were retired. Absent new firm generating assets, the United States risks entering a period of structural supply deficits in which peak demand exceeds available capacity in several regions as early as 2027 (NERC, 2025). The current supply is shaped by retirements, the investment-discouraging effect of price volatility, supply chain bottlenecks, the slow addition of renewables, and the untapped potential of small modular nuclear reactors.

Retirements

Over the past decade, the U.S. electric system has experienced a net decline in dispatchable generating capacity due to the accelerated retirement of coal, nuclear, and aging gas units. According to the EIA (EIA, 2024), between 2013 and 2023 the United States retired over 102 gigawatts of coal capacity and 15 gigawatts of nuclear capacity, while only adding 28 gigawatts of new gas-fired combined-cycle units capable of providing equivalent firm power.

These retirements raise two main problems. The first is that, holding all else equal, supply falls. Second, the retirements experienced in the United States shifted energy supply towards higher-variance energy sources. In other words, this shift has left the grid increasingly dependent on weather-dependent renewable energy and battery storage assets that do not provide low-to-no-variance baseload generation. This demonstrates the risks of a transition-only mindset. The current reality instead necessitates an energy addition approach: a strategy that retains all plausible solutions including fossil fuels, nuclear energy, and renewables, to ensure system adequacy

Volatile Prices Discourage Investment

Economists, investors, engineers, and others know that, holding mean returns constant, higher short-term variance discourages risk-averse investors (Dixit & Pindyck, 1994). In energy-only markets like ERCOT, needed capital recovery often relies on rare scarcity hours; price caps, demand inflexibility, and other imperfections create the classic “missing-money” problem—energy-market net revenues are frequently insufficient to cover new-build costs, deterring entry (Joskow, 2006, 2008). Many regions, therefore, add capacity/adequacy mechanisms to convert volatile scarcity rents into more bankable, forward revenues (Cramton et al., 2013). Decades of evidence document that electricity spot prices are intrinsically volatile, reinforcing investors’ bias to delay or demand higher risk-adjusted returns (Borenstein, 2002; Roques et al., 2008).Wholesale prices in ERCOT have swung from hundreds of hours at or below $0/MWh when wind and solar output are abundant to the $9,000/MWh system-wide cap during Winter Storm Uri in February 2021. This range reflects scarcity pricing in an energy-only market and creates extreme revenue volatility for market participants (Federal Energy Regulatory Commission (FERC), 2021; Potomac Economics, 2022).

Supply Chain Bottlenecks

The energy manufacturing supply chain is facing unprecedented challenges meeting the demand driven by AI and electrification. Even when new projects are approved, however, delivery timelines have been significantly lengthened due to transformer shortages, turbine backlogs, and the difficulty of finding other inputs that have extended lead times for new gas generation to over four years and transmission projects to more than a decade. Lead times for critical grid components such as large transformers and cables have nearly doubled since 2021, with transmission-scale units now requiring three to six years or more for delivery (IEA, 2025; Walton, 2024). Specifically, the average wait time for large power transformers is now more than 30 months, up from 12 months in 2018 (Trabish, 2025).

Natural gas has been the fastest-to-deploy firm generation source. Bottlenecks, however, due to supply-chain shortages, regional pipeline constraints, and extended lead times for turbine manufacturing are making natural gas a less viable option. Delays now stretch from four to seven years rather than the previous one-to-two-year timeframe (Anderson, 2025).(Abdelhady et al., 2025) highlight that manufacturing capacity for gas turbines is similarly constrained, with lead times having doubled since 2020 due to surging global demand and concentrated production in overseas supply hubs. The major turbine manufacturers (GE Vernova, Siemens Energy, and Mitsubishi Heavy Industries), however, are hesitant to commit to large-scale production increases. This caution is rooted in fears of a "bullwhip effect," where they see the current surge as potentially "distorted" or "inflated" demand (Ballard, 2025). Executives are haunted by the "traumatic episode" of the dot-com bubble, which was also marked by inflated assumptions about the internet's power demand and led to the bankruptcy of overextended power companies.

Consequently, manufacturers are opting for only modest capacity expansions, which analysts note are "not comparable to the magnitude of the demand uptick" (Ballard, 2025). This business decision, while rational for manufacturers, ensures that turbine supply will remain a critical bottleneck for grid development.

A third option, small modular nuclear reactors (SMRs), face additional constraints due to the nascent state of the nuclear fuel cycle and limited domestic capacity for reactor components. These constraints illustrate that the U.S. electricity supply challenge has a significant industrial component that should be addressed through strategic investment in domestic manufacturing, supply chain resilience, and federal procurement incentives.

Renewables Slow to Join

Although renewable projects account for over 80 percent of proposed new capacity in the United States, most of this capacity cannot be delivered due to interconnection backlogs and insufficient transmission infrastructure (Rand et al., 2024; U.S. Department of Energy (DOE), 2023). The lag between an investment decision and operational capacity is now stretching beyond five years for large-scale wind and solar projects (Abdelhady et al., 2025). The Lawrence Berkeley National Laboratory (LBL) (Rand et al., 2024) reports that more than 2,600 gigawatts of renewable and storage projects are currently waiting in interconnection queues—more than double total installed U.S. generation capacity—yet less than 20 percent of these projects are likely to reach commercial operation without major permitting and infrastructure reforms. In high-renewable power systems where transmission constraints limit grid integration, renewable generation has experienced reductions in effective capacity factors of up to 60 percent, indicating significant curtailment effects due to inadequate transmission (Kies et al., 2016).

Curtailment rates in regions such as ERCOT and the California Independent System Operator (CAISO) have reached double digits, with up to 21 percent of available wind and solar generation in some hours forced offline due to transmission congestion (EIA, 2024). The technical potential of renewables to supply the majority of U.S. electricity demand depends on the build-out of long-distance transmission (MacDonald et al., 2016). Without new transmission investments (discussed in detail below) renewable capacity becomes stranded.

The Untapped Potential of Nuclear Power and Small Modular Nuclear Reactors

Nuclear power has long served as a source of firm, zero-carbon baseload electricity. Unlike intermittent renewable resources, nuclear facilities operate continuously and provide stability to the grid. Small modular reactors (SMRs) represent a new generation of nuclear technology designed to be factory-produced, scalable, and deployable at industrial sites. SMRs can range from 50 to

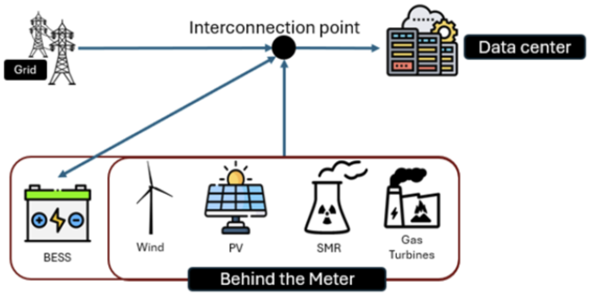
300 MW per module and offer significant advantages over traditional reactors, including lower upfront costs, shorter construction timelines, and enhanced safety features. A single 300 MW SMR can generate as much electricity annually as approximately 1,500 acres of solar or 15,000 acres of wind, making SMRs particularly suited for regions with limited land availability or high industrial demand (Iakovou, 2025).

Behind-the-Meter Applications and Energy Independence

Given rising demand and the supply issues described above, the large electric users have turned to producing their own energy "behind the meter" (BTM). Figure 4 shows how data centers, semiconductor fabrication plants, hydrogen production facilities, and electrified industrial clusters can increasingly deploy BTM energy. Generating electricity on-site avoids interconnection delays, transmission congestion, and wholesale market volatility (Abdelhady et al., 2025). In regions with long interconnection queues or insufficient grid capacity, BTM solutions could mitigate constraints on economic growth.

Different BTM options might vary in effectiveness under uncertain market conditions. To help firms understand the nuances behind different options under different conditions, (Abdelhady et al., 2025) evaluate optimal BTM energy strategies for large industrial facilities and data centers under significant market uncertainty. Their study evaluates volatile wholesale prices, unpredictable interconnection delays, and evolving emissions regulations. One key contribution is the application of a regret minimization framework. Rather than optimizing for a single forecast scenario, the framework identifies strategies that minimize worst-case performance losses across many possible futures, evaluating 219 distinct scenarios spanning 14 historical years (2011-2024) using full cross-validation and historical back-testing. The analysis tested BTM portfolio performance (Figure 5) and found that diversified BTM portfolios combining renewables, storage, and firm generation significantly outperformed grid-only strategies and reduce exposure to price volatility by up to 80% while maintaining operational flexibility.

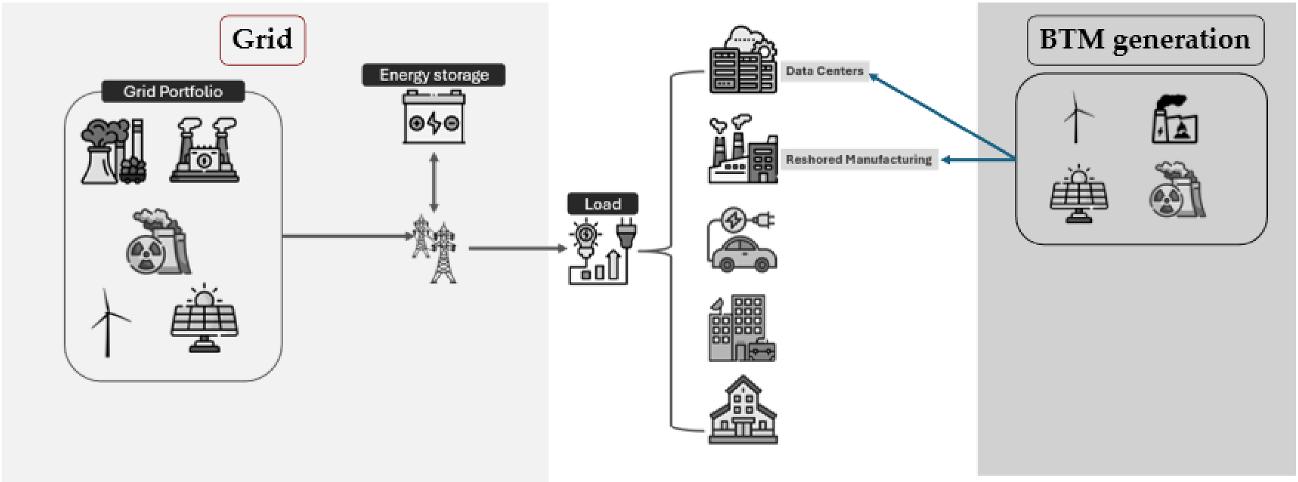
Figure 5: Conceptual System Configuration with BTM



Source: Abdelhady et al., 2025

Since we are operating in a volatile policy environment, their analysis also assesses BTM portfolio performance

Figure 4: Grid and Behind-the-Meter Generation Pathways



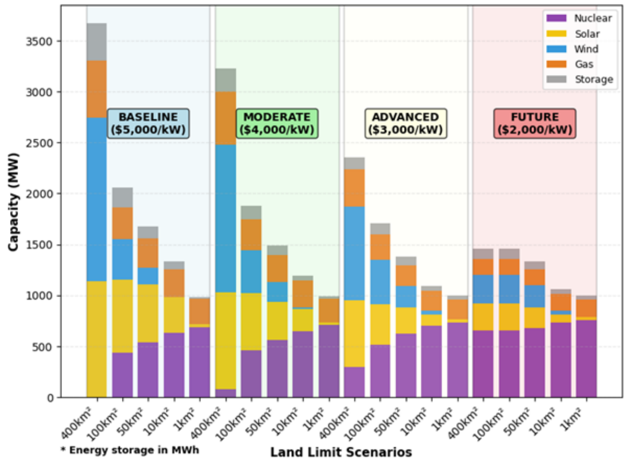
Source: Iakovou, 2025

under two policy-relevant constraint scenarios: facilities facing severe grid interconnection limits and facilities subject to strict emissions reduction requirements. Figure 6 shows four critical findings. First, portfolios combining three or more technologies plus grid access achieve average regret of 7.5%, which is a 7.5-fold improvement over grid-only strategies (56.6% regret). Second, grid independence reduces financial risk. Limiting grid dependence from 100% to 20% produces a 100-fold improvement in average regret (from 27% to 1.68%), demonstrating that energy independence mitigates risk (Figure 6a). Third, sustainability and resilience are complementary, rather than competing objectives. Emission reduction targets of 50-70% yield a six-fold reduction in regret (from 20% to 3.5%) at modest incremental cost (Figure 6b), revealing that decarbonization enhances rather than undermines portfolio robustness. Finally, energy storage exhibits nonlinear deployment patterns. Battery capacity peaks at 70% grid connection but declines under more restrictive scenarios (20% grid connection) because dispatchable generation becomes more cost-effective for long-duration backup under severe grid constraints.

Optimizing SMR Deployment in BTM Portfolios

BTM portfolios anchored by SMRs offer the most robust pathway for industrial competitiveness. As noted earlier, SMRs provide firm, around-the-clock power and stabilize voltage and frequency during renewable fluctuations. When paired with renewables and storage, SMRs act as the baseload anchor in optimal portfolios, particularly when land is limited (Abdelhady et al., 2025). As shown in Figure 7, SMRs increase their share of optimal portfolios as land availability declines.

Figure 7: Optimal BTM Energy Portfolio Composition Across Land Constraints and SMR Cost Scenarios

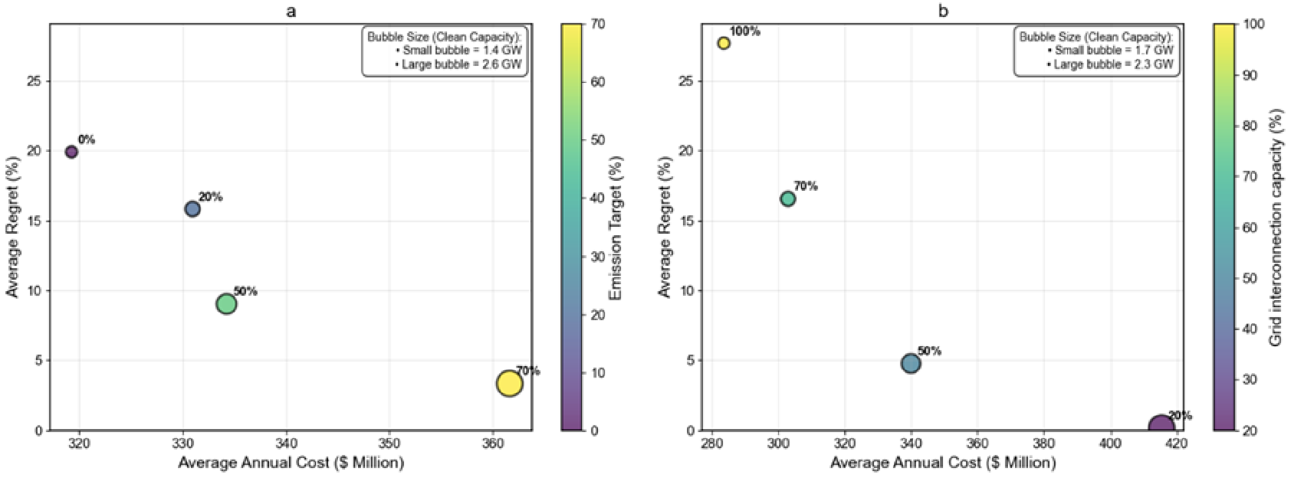


Source: Abdelhady et al., 2025

Figure 8 demonstrates that total system costs decrease significantly as SMR capital costs approach $2,000 per kilowatt, a threshold anticipated by leading developers.

Despite these advantages, SMR deployment faces institutional barriers, including lengthy Nuclear Regulatory Commission licensing processes, limited domestic fuel

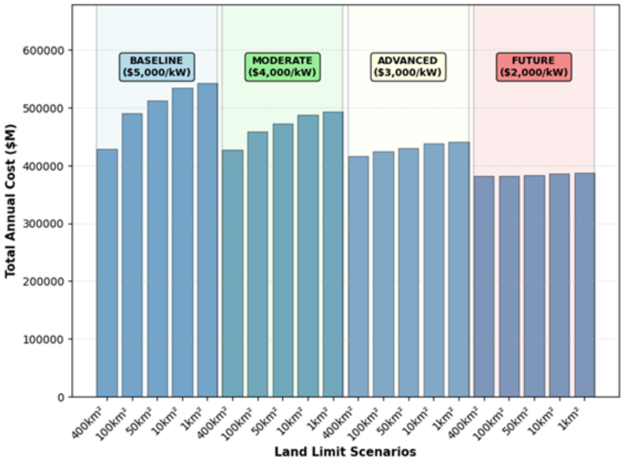
Figure 6: Impact of Emission Targets and Grid Interconnection Limits on Portfolio Performance and Clean Capacity Deployment



Source: Abdelhady et al., 2025

enrichment capacity for high-assay low-enriched uranium (HALEU), and supply chain constraints in reactor component manufacturing (World Nuclear Association, 2024).

Figure 8: Optimal BTM Energy Portfolio Composition Across Land Constraints and SMR Cost Scenarios



Source: Abdelhady et al., 2025

Figure 9 illustrates the geographic concentration of global fuel enrichment capabilities.

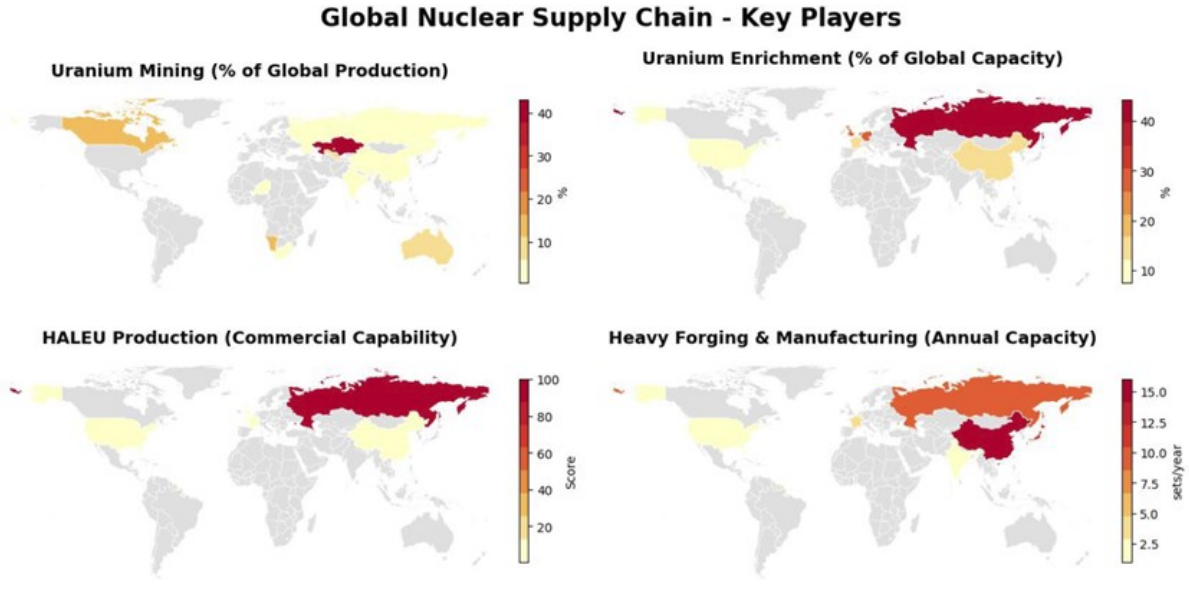
Adding SMR technology to behind-the-meter energy systems represents a fundamental shift in the U.S. electricity landscape. BTM systems reduce exposure to transmission delays, relieve congestion, and protect ratepayers from cross-subsidization disputes. SMR-enabled BTM portfolios transform the grid from a centralized, capacity-constrained network into a modular and resilient architecture aligned with industrial demand (Deese & Hansmann, 2025). This decentralized energy model allows the United States to meet rising electricity demand at the pace required by AI-driven data centers, advanced manufacturing, and strategic industries. In an economy where access to reliable electricity determines global competitiveness, integrating SMRs into BTM portfolios may be necessary to meet rising demand.

Figure 10 shows the end-to-end nuclear supply chain, highlighting U.S. dependence on foreign suppliers.

Nuclear Regulatory Hurdles and Public Support

Investment hurdles for firm nuclear generation remain high due to licensing friction and supply chain immaturity, leaving the United States increasingly reliant on variable generation that cannot guarantee reliability under peak demand conditions (Iakovou, 2025). One possible reason the regulatory barriers remain high is the perception of public opposition. What may be less known, how-

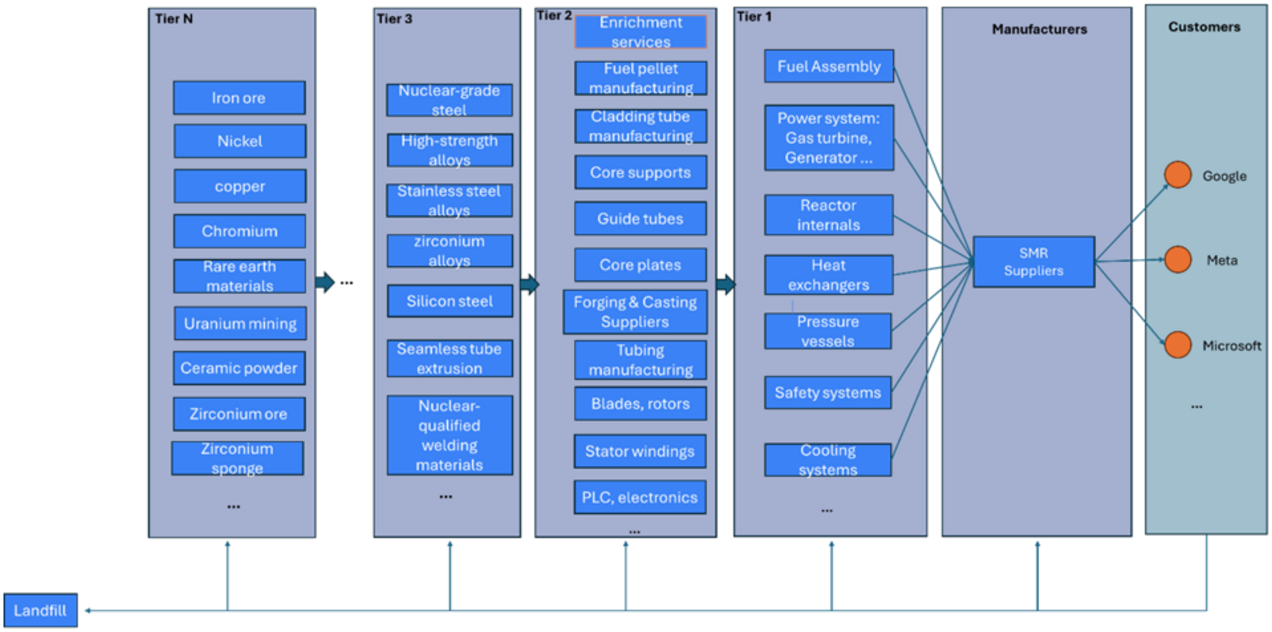
Figure 9: Geographic Concentration of Nuclear Supply Chain Capabilities



https://world-nuclear.org/

Source: (Iakovou, 2025; World Nuclear Association, 2024)

Figure 10: End-to-End Nuclear Supply Chain: From Raw Materials to Reactor Deployment



Source: Iakovou, 2025

ever, is that public support for nuclear energy in the United States has risen markedly in recent years. Neighboring communities around existing nuclear plants report very high favorability—88 % of plant neighbors versus 77 % of the general public in 2022 (American Nuclear Society, 2022). Gallup surveys show that in 2023 and 2025, support among U.S. adults reached highest levels in a decade and near-record highs, respectively (Brenan, 2023, 2025). Research also indicates that psychological factors affect nuclear energy attitudes, while demographic factors such as gender influence risk aversion and thereby support for nuclear technologies (Borghans et al., 2009; Hacquin et al., 2022). Together, these findings reflect an evolving public opinion landscape in which nuclear energy is increasingly seen as a viable part of the U.S. energy mix.

Transmission

“Transmission” is the physical network can carry flow that determines whether generation investments, electrification policies, and reliability measures achieve their intended outcomes and, therefore, may the most important current constraint on the U.S. energy grid. Transmission capacity determines both macroeconomic performance and environmental outcomes. A national high-voltage direct current (HVDC) transmission backbone could enable the United States to meet up to 80 percent of electricity demand with renewable energy at no additional cost by allowing power to flow from high-resource regions to major demand centers (MacDonald et al., 2016). Even modest improvements in grid efficiency could unlock capacity equivalent to 60 new natural gas power plants without constructing a single new facility (Deese & Hansmann, 2025). (Duan & Motter, 2025) provide empirical evidence showing that congestion undermines the emissions benefits of electric vehicle adoption because constrained regions must rely on fossil-heavy marginal generation when renewable power cannot reach load centers.

Transmission constraints impose substantial economic costs. Congestion cost U.S. consumers an estimated $11.5 billion in 2023 because low-cost generation could not reach high-priced regions. The Department of Energy’s National Transmission Needs Study (DOE, 2023) estimates that every dollar invested in transmission yields between two and four dollars in economic benefits by lowering wholesale prices, reducing blackout risk, and improving access to diverse generation resources. Expanded transmission enhances reliability by enabling geographic diversity in supply and reduces reliance on expensive peaker plants that operate only during extreme conditions. Studies by Energy Innovation (Energy Innovation, 2024) and the Brattle Group (Tsuchida et al., 2023) show that advanced conductors and grid-enhancing technologies could unlock tens of gigawatts of latent capacity within two years, meeting near-term load growth from data centers without constructing new lines.

Expansion

Unfortunately, transmission expansion has slowed significantly. Fewer than 100 miles of new high-voltage interstate transmission were added in 2023, compared to an average of 1,700 miles per year a decade earlier (Shreve et al., 2024). Transmission constraints directly increase emissions because electric vehicle charging in constrained regions relies on carbon-intensive peaker plants rather than lower-cost renewable generation available elsewhere on the grid (Duan & Motter, 2025; Xue et al., 2022) demonstrate that modern grid reliability depends less on aggregate resource adequacy and more on the ability to move electricity to where it is needed at the moment it is needed, which, according to several studies, might be more of a function of regulation than technology or resources.

Regulation and Policy Bottlenecks

Some of the United States' most pressing transmission challenges stem not from technology but from a regulatory framework built for a different energy era. Political and regulatory barriers now pose the greatest obstacles to transmission expansion. Transmission planning and approval remain fragmented among fifty state utility commissions, multiple regional transmission organizations, and independent system operators, each governed by distinct rules and political pressures. The Federal Energy Regulatory Commission regulates wholesale markets and interstate transmission but lacks authority over siting, permitting, and eminent domain, which remain under state control (Tsuchida et al., 2023). This structure once served an electricity system defined by local, predictable demand but is poorly suited to a landscape dominated by large, rapidly expanding loads such as data centers and electric arc furnaces that can consume hundreds of megawatts and shape regional grid conditions (Abdelhady et al., 2025). Fragmentation allows individual states to block or delay projects that would strengthen regional reliability and national competitiveness. North Dakota, joined by Montana and several southern states, filed a complaint to block a $22 billion Midwestern transmission expansion approved by MISO, arguing that their ratepayers should not subsidize infrastructure enabling other states to meet clean energy targets. Minnesota regulators responded that preventing the project would undermine reliability and economic competitiveness due to surging electricity demand from data centers and manufacturing (Orenstein, 2025).

Planning, permitting, and constructing new high-voltage transmission projects routinely takes more than a decade, and total development costs frequently exceed $3 million per mile for 500 kV lines (Clack et al., 2017; Tsuchida et al., 2023).

Cost allocation disputes compound the problem, as states resist paying for lines that export or import power across borders even when such projects lower wholesale prices nationwide. Compensation frameworks further misalign incentives—utilities earn regulated returns on new infrastructure but have no comparable mechanism for investing in performance-enhancing solutions such as reconductoring or grid-enhancing technologies. This throughput incentive discourages low-cost improvements that could relieve congestion and improve reliability (Tsuchida et al., 2023).

POTENTIAL SOLUTIONS

Policymakers must act across multiple fronts to address the surge in electricity demand while safeguarding grid reliability and decarbonization goals. The recommendations below are not mutually exclusive. A comprehensive policy approach must combine national-scale grid investments with localized solutions tailored to the unique requirements of hyperscale data centers and preserve grid reliability.

Federal Policy Recommendations

1. *Enhance Grid Research and Data*

The United States lacks the forecasting infrastructure needed to plan for twenty-first-century electricity consumption. Existing reliability assessment tools were developed for static load profiles and do not adequately capture emerging risks from speculative load growth, extreme weather, or coordinated cyberattacks (Sultan & Hilton, 2019; Xue et al., 2022). Furthermore, LBL research highlights that utility investments often lag reliability degradation by several years due to inadequate data visibility (Eto et al., 2012). Enhanced research capabilities that include real-time data, grid-enhancing technologies, and advanced forecasting models would allow policymakers to identify vulnerabilities early, optimize asset utilization, and evaluate the benefits of strategic investments. Federal and private-sector funding for the national laboratories and research universities, coupled with data-sharing mandates for utilities, would go a long way towards modernize planning methodologies and help the U.S. anticipate rather than react to grid stress.

2. *Establish a National Transmission Planning and Cost Allocation Framework*

State-level control over siting and permitting creates delays that undermine regional reliability and economic development. Federal leadership is therefore increasingly essential because the current state-based transmission approval system undermines national economic competitiveness and grid reliability. A FERC-led national framework with enforceable planning timelines and cost allocation rules would ensure that investments reflect regional and national benefits rather than narrow state interests (Orenstein, 2025). DOE loan guarantees and transmission tax credits are two possible federal financing tools that could treat transmission as strategic infrastructure and would follow the precedent set by established support for semiconductor manufacturing and hydrogen hubs (DOE, 2024). By aligning cost allocation with shared system benefits, federal policy would accelerate investment at the scale required to meet rising demand and maintain industrial leadership (Abdelhady et al., 2025).

Traditional cost-of-service regulation incentivizes infrastructure expansion rather than efficient use of existing assets. Performance-based regulation would shift utility incentives toward reliability, congestion reduction, and efficient transmission (Larsen et al., 2016). Evidence from competitive markets such as ERCOT shows that performance-based incentives accelerate integration of new generation while maintaining reliability (Deese & Hansmann, 2025). FERC should establish national standards that tie utility earnings to measurable outcomes such as increased transfer capability and reduced congestion, rather than rate base growth.

3. *Accelerate Deployment of Advanced Transmission Technologies*

The Department of Energy's Advanced Conductor Scan Report (Idaho National Laboratory (INL), 2023) shows that more than half of existing high-voltage corridors can double throughput through reconductoring with high-temperature, low-sag conductors, reducing deployment timelines to two to three years (Chojkiewicz et al., 2024). Grid-enhancing technologies such as dynamic line rating and power flow optimization can unlock an additional 20–200 percent capacity (ENTSO-E, 2025; Karimi et al., 2018).

The Brattle Group (Tsuchida et al., 2023) concludes that immediate deployment of these technologies could unlock tens of gigawatts without new transmission lines. Federal incentives should reward utilities for measurable performance improvements instead of capital expenditures, ensuring these proven technologies are deployed at scale (Deese & Hansmann, 2025).

4. *Expand Opportunities for Scale Small Modular Reactors (SMRs)*

Small modular reactors offer the only zero-carbon baseload technology capable of providing reliable power at the scale required by hyperscale data centers and advanced manufacturing facilities (Abdelhady et al., 2025). Deployment, however, is delayed by licensing bottlenecks and a lack of domestic High-Assay Low-Enriched Uranium (HALEU) fuel production (World Nuclear Association, 2024). Federal policy should prioritize SMRs under the Defense Production Act, streamline NRC licensing through standardized certification, and provide production tax credits and loan guarantees similar to those available for renewables (Deese & Hansmann, 2025).

5. *Establish National Incentives for Demand Flexibility and Grid Services*

Federal incentives are needed to integrate flexible load into grid reliability planning. Research shows that flexible data center operations can reduce peak demand and defer transmission investment while supporting continuous industrial productivity (Abdelhady et al., 2025). Texas Senate Bill 6 (2025) demonstrates how mandatory curtailment requirements can enhance grid resilience, while pilot programs in California and New York show that incentives can drive voluntary participation (Texas Legislature, 2025). Federal policy should provide demand-response payments, accelerated depreciation for flexible infrastructure, and priority interconnection for firms that commit to operational flexibility, aligning private investment with national reliability goals (Larsen et al., 2016; Orenstein, 2025).

State Policy Recommendations

1. *Establish Multi-State Compacts for Transmission Siting and Permitting*

Regulatory responses are emerging but remain fragmented across jurisdictions. Texas Senate Bill 6 (2025) requires large data centers to curtail consumption during grid emergencies. Oregon is considering mandates for grid upgrades and demand response requirements in the absence of federal coordination, multi-state compacts would allow states to coordinate permitting timelines, designate shared transmission corridors, and streamline environmental reviews (Orenstein, 2025). This structure preserves state authority while enabling states to jointly approve infrastructure that delivers regional benefits. Compacts would reduce regulatory uncertainty, accelerate deployment of critical transmission projects, and prevent individual states from acting as veto points for infrastructure essential to national competitiveness.

2. *Modernize Cost Allocation to Reflect Regional Economic Benefits*

Current cost allocation rules often prevent approval of transmission projects because states resist paying for infrastructure located outside their borders. Yet modeling from the Department of Energy demonstrates that transmission investments reduce wholesale electricity prices, improve reliability, and attract industrial development across entire regions ((FERC), 2024). States should adopt beneficiary-pays models that account for long-term economic benefits rather than limiting cost recovery to physical location. This reform would align regulatory decisions with the economic realities of an interconnected grid and prevent states from blocking projects that provide regional advantages (Abdelhady et al., 2025).

3. *Enable Deployment of Behind-the-Meter and Distributed Energy Resources*

States can relieve pressure on bulk transmission systems by enabling behind-the-meter generation, storage, and microgrids at industrial and data center sites. Studies show that diversified behind-the-meter portfolios that include renewables, storage, and small modular reactors could significantly reduce exposure to price volatility and improve reliability for large energy consumers (Abdelhady et al., 2025). Updating zoning rules, interconnection standards, and permitting regulations would allow states to accelerate deployment of these local generation assets. This approach supports economic development while reducing downstream strain on transmission networks (Deese & Hansmann, 2025).

4. *Incentivize Demand Flexibility to Reduce System Costs*

Peak demand drives transmission and generation investment, yet much of that demand can be shifted without harming industrial productivity. Evidence shows that flexible operations from large electricity users can reduce peak load, lower system costs, and defer infrastructure expansion (Abdelhady et al., 2025). States should integrate demand flexibility into their resource planning requirements and use incentives (e.g., reduced tariffs, tax credits, or accelerated depreciation) to encourage firms to participate in demand response programs. ERCOT emergency operations studies demonstrate that load curtailment during scarcity events helped maintain system stability and prevent widespread outages (ERCOT, 2023; Larsen et al., 2016). By embedding flexibility in regulatory frameworks, states can lower costs for all ratepayers while improving resilience.

Utility and Grid Operator Policy Recommendations

1. *Deploy Existing Technologies to Expand Grid Capacity Immediately*

Utilities can unlock near-term capacity by modernizing existing infrastructure rather than waiting for new transmission lines. Reconductoring existing corridors with high-temperature, low-sag (HTLS) conductors can double transmission capacity using current rights-of-way, while dynamic line rating and power flow control technologies optimize transfer capability in real time DOE, 2023). The Brattle Group (Tsuchida et al., 2023) finds that these solutions could unlock tens of gigawatts of capacity within two years. Utilities should adopt these tools proactively to reduce congestion, improve reliability, and integrate new industrial and data center loads without imposing significant costs on ratepayers.

2. *Incorporate Long-Term Industrial Load Growth into Resource Planning*

Rapid growth in data centers, electric arc furnaces, hydrogen production, and AI compute clusters requires utilities to integrate forward-looking load forecasts into their planning models. Abdelhady et al., (2025) show that failure to account for speculative industrial load leads to chronic underinvestment and planning uncertainty. Utilities should incorporate long-term demand projections and scenario-based forecasting to ensure the grid can support future industrial development. This approach enables proactive infrastructure deployment and reduces the risk of last-minute capacity shortages that require costly emergency measures.

3. *Require Firm Load Commitments to Reduce Speculative Risk*

Utilities increasingly face interconnection requests from large energy users that reserve grid capacity but later reduce or cancel their plans, creating stranded cost and uncertainty. Enforcing firm commitments with interconnection deposits, long-term service agreements, or capacity payments would protect ratepayers and provide utilities with the financial certainty needed to invest in new infrastructure (Abdelhady et al., 2025). These measures would ensure that speculative loads do not tie up planning resources or delay projects needed to serve committed economic activity.

Recommendations for Large Electricity-Consuming Firms

1. *Provide Firm Commitments to Support Grid Investment*

It seems probable that large electric users understand that, without long-term guarantees, speculative interconnection requests expose utilities and ratepayers to stranded asset risk (Abdelhady et al., 2025). It is therefore in the mutual interests of firms to be increasingly open to long-term service agreements or post interconnection deposits to secure capacity. These commitments would enable utilities to plan proactively, reduce financing costs, and ensure that infrastructure development aligns with real economic activity.

2. *Invest in Behind-the-Meter Generation and Storage*

Reliance on grid-delivered power is becoming a competitive liability as transmission congestion and interconnection delays threaten operational continuity. Research shows that diversified behind-the-meter portfolios stand an excellent chance of significantly reducing exposure to wholesale market volatility and improving resilience (Abdelhady et al., 2025). Adopting on-site generation as a strategic asset would help control energy costs, ensure reliability, and support continuous operations during grid stress. The most promising options are renewables, storage, and small modular reactors.

3. *Participate in Demand Flexibility and Grid Services*

Flexible load operations can deliver both cost savings and regulatory advantages. Firms that can curtail or shift consumption during peak periods help stabilize the grid and reduce the need for expensive infrastructure expansion (Larsen et al., 2016). Since data centers can time-shift AI computing workloads to off-peak hours, firms can provide ancillary services that support grid reliability (Abdelhady et al., 2025). By participating in demand response programs, firms can secure priority interconnection, access lower tariffs, and demonstrate compliance with emerging regulatory standards.

4. *Integrate Energy Strategy into Long-Term Competitiveness Planning*

Electricity has become a core driver of industrial competitiveness, not a background utility input. Firms that secure reliable, cost-predictable energy sources will dictate the geography of future economic growth. Evidence from (Abdelhady et al., 2025) shows that regions with abundant, low-cost clean energy are capturing investment in advanced manufacturing, data infrastructure, and emerging technologies. Firms should incorporate energy independence and resilience as a primary criterion for site selection and capital planning.

CONCLUSION: WHAT IS AT STAKE?

Economic competitiveness and growth along with national security are at stake in the electric generation debate. Advanced industries, such as artificial intelligence, semiconductor fabrication, and clean technology manufacturing are extraordinarily electricity intensive. Firms making location decisions increasingly prioritize energy reliability, cost certainty, and regulatory predictability. China, recognizing the centrality of electricity to strategic industries, has made massive long-term investments in grid buildout and capacity expansion. By contrast, the United States faces interconnection queues totaling more than double the current grid's capacity and projects are waiting years for approval (Deese & Hansmann, 2025). Regulatory bottlenecks and supply chain delays undermine the ability of the grid to meet demand in a timely manner; the "clock times" of how current grid expansion capabilities and demand imposed by data centers are severely non-harmonized. This widening gap between electricity supply and demand threatens to push investment, jobs, and innovation overseas.

There are also mounting consequences for households and small businesses. In the first half of 2025 alone, utilities requested or received approval for $29 billion in rate increases, signaling years of higher electricity bills for consumers (Deese & Hansmann, 2025). Rising prices are already a source of financial stress, with two-thirds of American households citing utility bills as a burden. Yet these cost increases are not being driven solely by new investment in energy resources but by inefficiencies and delays in the existing system. The Star Tribune report makes clear that when transmission projects become politicized, the economic costs are borne disproportionately by ratepayers in regions investing in economic growth. The dispute over who pays reveals a deeper problem—the current system lacks a mechanism to allocate costs in proportion to the national benefits of a reliable and integrated grid.

The transmission dispute in the Upper Midwest makes clear that the United States faces not just a technical challenge but a governance challenge. As energy becomes a strategic commodity, decisions about who pays for infrastructure have become proxies for broader ideological battles about climate policy, industrial strategy, and federal versus state authority. Without national leadership to align incentives and streamline permitting, transmission will remain a chokepoint constraining both economic growth and decarbonization goals. The purpose of this white paper is therefore not simply to document the emerging electricity crisis, but to identify economically grounded, politically feasible solutions that can optimize existing infrastructure, accelerate transmission deployment, and secure reliable, affordable electricity for all regions of the country. Meeting this moment requires moving beyond zero-sum politics toward a framework that treats electricity as essential infrastructure for national prosperity and security in the twenty-first century.

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NOTES

[1] We define resilience as the grid's ability to anticipate, withstand, and recover from disruptions.

[2] "Queue growth" refers to the volume of proposed generation and large-load projects (such as data centers) awaiting interconnection to the grid.

[3] ERCOT's June 17, 2025 deck provides the official interconnection-queue totals and composition, plus a "Current Large Load Interconnection Queue" slide showing ~156 GW of large loads seeking interconnection as of June 2, 2025. The "Large Load Interconnection Queue" captures demand growth from energy-intensive customers such as AI data centers and crypto facilities.

[4] Nameplate generation capacity is the maximum amount of electricity a power plant is designed to produce under ideal conditions.

[5] ERCOT's June 2025 deck provides the official generation queue totals and composition, plus a "Current Large Load Interconnection Queue" slide with observed/approved stages; the "~156 GW by 2030" figure for large loads is reported in White & Case's summary of ERCOT's June 2, 2025 snapshot.

[6] Curtailment rates measure the percent of available electric generation that is not used or delivered even though it could have been produced.

[7] Dispatchable generating capacity includes sources that grid operators can apply to, or remove from, the grid to meet real-time needs.

[8] "Regret Minimization" is an optimization approach that uses "regret" as a decision-making metric measuring opportunity cost. "Regret" quantifies how much more a chosen portfolio costs compared to the theoretically optimal portfolio that could have been selected if future market conditions were known in advance. For example, a portfolio with 10% regret costs 10% more than the perfect choice that would have been made with perfect foresight of that year's electricity prices.

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