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Pain at the Plug

Five-Pillar Energy Plan for American Abundance

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Introduction

“Pain at the plug” is replacing “pain at the pump” as the defining energy stress test for American households. For decades, gasoline prices served as the barometer of economic health and political stability, shaping everything from consumer sentiment to presidential approval ratings. Today, electricity bills assume that same role. Since 2020, U.S. retail electricity prices have risen faster than overall inflation. As the datacenter buildout progresses from forecasts to fruition, we expect pain at the plug to be a hotly debated issue in midterm elections and utility resource planning meetings as electricity prices pit AI against constituents.

The current surge in electricity costs reflects more than just inflation, it marks a profound structural shift. The COVID-19 pandemic exposed the vulnerabilities of an economy that prioritized efficiency over resilience for decades. Now, a counterforce is emerging: a coordinated push toward reindustrialization and electrification, coupled with the rapid expansion of AI datacenters, is driving unprecedented demand for electricity. Unlike the oil shocks of the 1970s, today’s pressure isn’t rooted in supply shortages. Instead, the U.S. faces the challenge of rebuilding its energy and power infrastructure after 25 years of stagnation. Key hurdles include modernizing an aging grid, reestablishing reliable baseload generation, and managing the complexities introduced by intermittent renewable sources.

This report explores a critical yet often overlooked driver of rising electricity prices: the variability inherent in renewable energy generation. Solar and wind have been prophesied as the panacea of energy—cheap, clean, and fast to deploy. Of these claims, we find the notion of “cheap” to be the most misleading. We argue that this belief is rooted in flawed interpretations of levelized cost of electricity (LCOE) and repeated so frequently it has taken on the weight of accepted truth. Our goal is to challenge this misconception and reintroduce a physics-based perspective. We advocate for energy return on investment (EROI) as a more robust framework to guide the rebuilding of U.S. energy and power policy. We believe EROI analysis properly accounts for the impacts of variability and its cascading effects on the grid. It provides a more accurate assessment, in our view, of the true cost of solar and wind energy, ultimately highlighting the advantages of baseload such as nuclear and dispatchable sources such as natural gas and battery storage. In our view, continuing along the current renewable-heavy path to meet AI-driven energy demand risks compromising energy reliability, technological advancement, and security. The most immediate impact may be felt by consumers, as rising renewable penetration drives up retail electricity prices, while still falling short of the scale and consistency required to power AI infrastructure.

The five pillars outlined in this report are designed to reshape the national energy conversation, grounding it in physics through the adoption of EROI, and to offer a roadmap for achieving American energy abundance. The goal of these pillars is to meet the rising demands of AI without forcing a trade-off between innovation and affordability for everyday consumers.

Executive Summary

Energy abundance is a prerequisite for sustained economic expansion, industrial competitiveness, and national security. The AI data center buildout and reshoring key industries like chip manufacturing are strategic imperatives that cannot occur without a massive increase in dispatchable baseload energy. We believe U.S. energy policy should be built on the foundation of energy return on investment (EROI). This approach is the great energy equalizer, centering technology comparison on physics and thermodynamics and ignoring politics and ideologies. Applying this rubric, it is clear to us that high EROI technologies—such as nuclear, natural gas, and battery energy stationary storage (BESS)—are best positioned to deliver energetic and economic abundance. Renewables are not up to the task; the variability foisted on the grid has increased electricity pricing while decreasing resiliency, all while consuming billions in taxpayer subsidies and debt to obfuscate the low EROI, in our view.

Nuclear, especially uprating and restarting existing plants, is the highest EROI energy source we have to date. The Trump administration has made nuclear core to its energy policy, especially Secretary of Energy Chris Wright. The nuclear sector has enjoyed a significant run, and our names under coverage have been large beneficiaries of the trend. For example, a critical gap in the U.S. nuclear sector is the domestic nuclear fuel supply chain, and Centrus Energy plays a key role in uranium enrichment for the U.S. commercial nuclear fleet and the next generation of reactors. BWX Technologies is a leader in nuclear component manufacturing and reactor services, with deep ties to both commercial and government nuclear programs, positioning it to scale with increased deployment of nuclear assets. In addition, Oklo represents the frontier of nuclear innovation, developing microreactors designed for distributed power generation, ideal for remote operations, data centers, and industrial sites. We continue to view BWX Technologies, Centrus Energy, and Oklo as well positioned in the revitalization of the nuclear industry. That said, any significant capacity additions are out past 2030, and in in the meantime, the U.S. needs to take advantage of its abundance of natural gas reserves.

Natural gas is one of the U.S.'s greatest resources and a critical source of energy. Domestic natural gas demand is likely to increase by over 25% in the next decade, driven by two trends: rising domestic consumption from AI data centers coming online and a surge in LNG exports as new trains commence operations. Fortunately, the U.S. currently holds nearly 5 trillion cubic feet (Tcf) of natural gas underground in storage, with the majority situated in the Atlantic region and material levels in the Mid-Continent and Gulf Coast regions. Reserves are expected to materially grow over the next five years as production ramps up in the Appalachian, Haynesville, and Permian Basins. This dynamic signals high upside potential for the largest upstream producers; EQT Corporation and Expand Energy, which together account for over 10% of U.S. natural gas production. We expect free cash flow yields for each to rise by over 200 basis points for every $1/Mcf rise in natural gas prices, which we believe would allow several other smaller E&Ps to benefit, such as Gulfport Energy in our coverage, as well as noncovered companies Range Resources, Antero Resources, and Comstock Resources. Increased demand will place additional pressure on takeaway capacity, which is already constrained in various regions. For example, Waha (Permian Basin) natural gas hub prices recently collapsed to record lows under -$9/Mcf, negatively affecting company revenues for the sale of associated natural gas. Similar to upstream, increased demand should reflect positively on various midstream and infrastructure providers, such as Williams Companies, Targa Resources, Enterprise Products Partners, Kinder Morgan, Energy Transfer, MPLX LP, and ONEOK, all of which we view as well positioned to benefit from the rising natural gas demand.

As the U.S. energy grid adapts to the rising demands of electrification, natural gas remains a cornerstone of grid reliability due to its ability to rapidly dispatch power during peak load periods and compensate for the intermittency of renewables. This dynamic also directly benefits companies like GE Vernova in our coverage, and others such as Siemens Energy, Mitsubishi Heavy Industries, and Baker Hughes, which are deeply embedded in the natural gas value chain. GE Vernova and Siemens

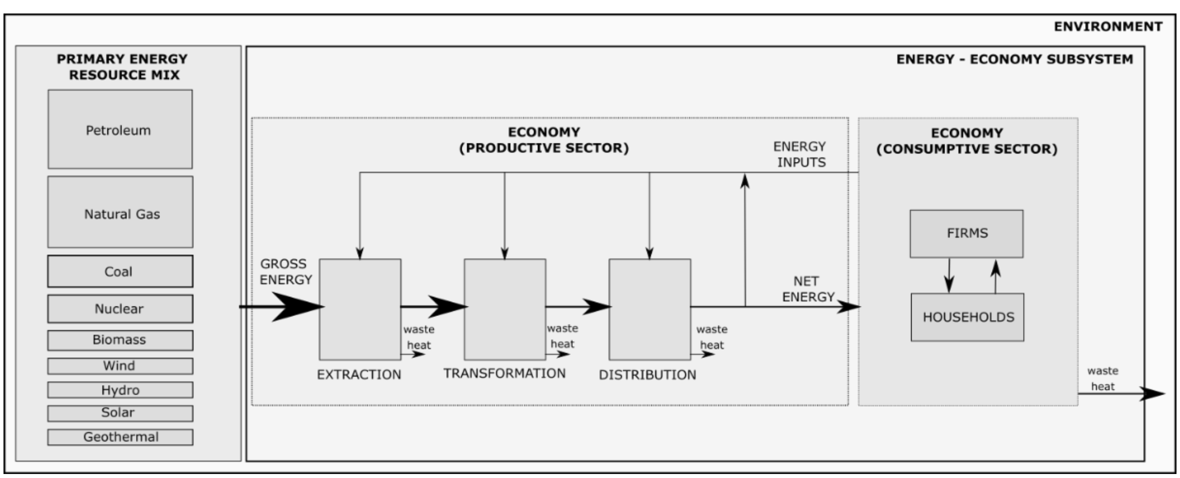
Energy are at the forefront of developing and maintaining high-efficiency gas turbines that enable fast, flexible power generation. Mitsubishi Heavy Industries enhances this capability with advanced turbine systems and integrated energy platforms that support gas infrastructure. Baker Hughes, with its extensive footprint in upstream gas services and LNG technologies, is uniquely positioned to capitalize. As utilities and grid operators invest in dispatchable energy assets to ensure system resilience and meet peak demand, these companies stand to benefit from increased infrastructure spending, long-term service agreements, and innovation-driven growth. This trend offers a strategic pathway to secure exposure to the essential technologies that underpin a reliable energy grid, in our view.

Batteries are often viewed merely as a supplement to renewables, aimed at smoothing out variability. We believe this perspective significantly undervalues their potential. The U.S. grid is designed around peak load, yet baseload assets, particularly natural gas, operate at just 55% utilization on average. By integrating BESS with existing natural gas infrastructure and boosting utilization to levels comparable with nuclear (around 90%), we could unlock an additional 196 gigawatts (GW) of power capacity, without building a single new generation asset. This application is not well understood, but we expect this strategy to be realized quickly by utilities and independent power producers (IPPs), increasing BESS demand and installations throughout 2030. Tesla's Megapack and Megablock products are best positioned in the U.S. market, and we expect the energy business to become a larger part of the Tesla story as the company ramps up production significantly in 2026.

The Core Idea: Energy Profitability Determines Alpha for the Market and Society
We submit that the government should only back energy sources that provide societal value greater than the cost of the capital being deployed. We measure this using the concept of EROI. We calculate that the U.S. economy has a metabolic energy breakeven of 7:1 and increasing. Thus, policy support should be limited to technologies that exhibit an EROI above 7:1, meaning they return at least seven units of energy for every unit of energy spent building and operating them.

Social stability, defense systems, and economic abundance are underpinned by a reliable energy sector. Reliable energy is a hallmark of a productive economy, and unreliable energy leads to economic instability. Variable assets undermine reliability and are making grid systems vulnerable, and therefore risking economic turmoil. Spain and Portugal's April 28 blackout should serve as a warning of the potential devastating impacts of energy systems that are ill-prepared for high levels of variable renewable energy penetration.

Exhibit 1
Pain at the Plug
Energy Return on Investment



Source: William Blair Equity Research

Pillar I – Build Firm Power Fast; Firm Power Is the New Clean Energy

A reliable energy policy begins with a firm foundation of dependable power sources (e.g., nuclear, natural gas, and battery storage). These technologies form the backbone of a resilient grid by providing consistent, dispatchable baseload power that can operate regardless of weather conditions or time of day. Nuclear energy offers zero-carbon generation with high-capacity factors, while natural gas provides flexibility and rapid ramping capabilities to meet fluctuating demand. Battery storage complements both by balancing short-term variability and enhancing grid stability. Together, these sources should ensure energy security, reduce reliance on intermittent renewables, and create a stable platform upon which broader decarbonization strategies can be built.

Exhibit 2
Pain at the Plug
Building Firm Power Fast: Nuclear Natural Gas & Battery Storage

Energy Source	Key Points	Capacity Potential
Nuclear	- Restart, extend, and upgrade existing reactor fleet - Standardize reactor designs so we stop reinventing the wheel (FOAK to NOAK) - Build fuel supply in the U.S. and guarantee long-term government contracts for industries that need 24/7 power (like semiconductor fabs, steel plants, shipyards)	- Over 4.4 GWs across 4 reactors are in the process of recommissioning - Over the past five years, 7 plants and 13 reactors have been granted operation license renewals, saving 13 GW of power from leaving the grid. -There is 5 GW of uprate potential across 65 reactors under GEV's service contracts
Natural Gas	- The EROI of natural gas is high, and underappreciated - The U.S. maintains a critical supply of natural gas to serve the expected increase in demand without causing significant price shocks to the market.	- In the first half of 2025 alone, 41.5 GW of gas generation capacity was ordered, marking a 37% year-over-year increase and the highest six-month total on record. - If U.S. utility scale generation is 4,200 TWh/year today, a 2% CAGR adds 920 TWh over 10 years. At a 43% gas share, this translates to 396 TWh/year of new gas fired generation, requiring 7.3 Bcfpd of additional average gas burn by year 10.
Battery Storage	- Use batteries to increase utilization of baseload assets closer to peak output - Pair batteries with existing natural gas and coal plants	- Pairing BESS with the installed baseload will allow higher utilization rates, opening almost 196 GW of peak power capacity, easily supplying the additional load growth

Source: William Blair Equity Research

Nuclear Restarting, Extending, and Uprating

Restarting a nuclear facility is the highest EROI source of energy we have, because the inputs have already all been accounted for, and minimal additional energy is required. Utilities, IPPs, hyperscalers, and other industry participants are recognizing this, and over 4.4 GWs across four nuclear reactor facilities are in the process of recommissioning. We believe it is critical for the U.S. to continue to take advantage of the low-hanging fruit by restarting nuclear reactors.

Exhibit 3
Pain at the Plug
Announced Restarts of Nuclear Reactors

Nuclear Plant	Location	Capacity	Reactor Type	Date Closed	Target Restart	Owner / Operator	Funding / Power Offtake
Palisades	MI	800 MW	PWR	May 2022	Late 2025	Holtec	DOE loan guarantee ($1.52B); Wolverine Power Cooperative & Hoosier Energy PPAs
Three Mile Island	PA	835 MW	PWR	September 2019	2027	Constellation Energy	Microsoft 20-year PPA for 100% output (AI/data centers)
Duane Arnold	IA	600 MW	BWR	October 2020	2028–2029	NextEra Energy	TBD; exploring data center power sales; FERC waiver approved (Aug 2025)
V.C. Summer Units 2 & 3	SC	2,200 MW	PWR	Construction halted July 2017	Mid-2030s	Santee Cooper	Santee Cooper seeking private acquisition; proposals include utilities, nuclear developers, private capital

Source: NRC, Holtec, Constellation Energy, NextEra Energy, Reuters, William Blair Equity Research

Of the 94 commercial nuclear reactors in the U.S., 31 have operating licenses that will expire within the next decade—representing 27.4 GW of power, or 28% of our current 97 GWs of nuclear power. To meet the electricity demand load inflection without pushing up consumer electricity pricing, it is essential that the U.S. avoids undermining its energy production capacity by retiring the U.S. nuclear fleet, which is the most cost-effective, heavily utilized, zero-emission baseload power source.

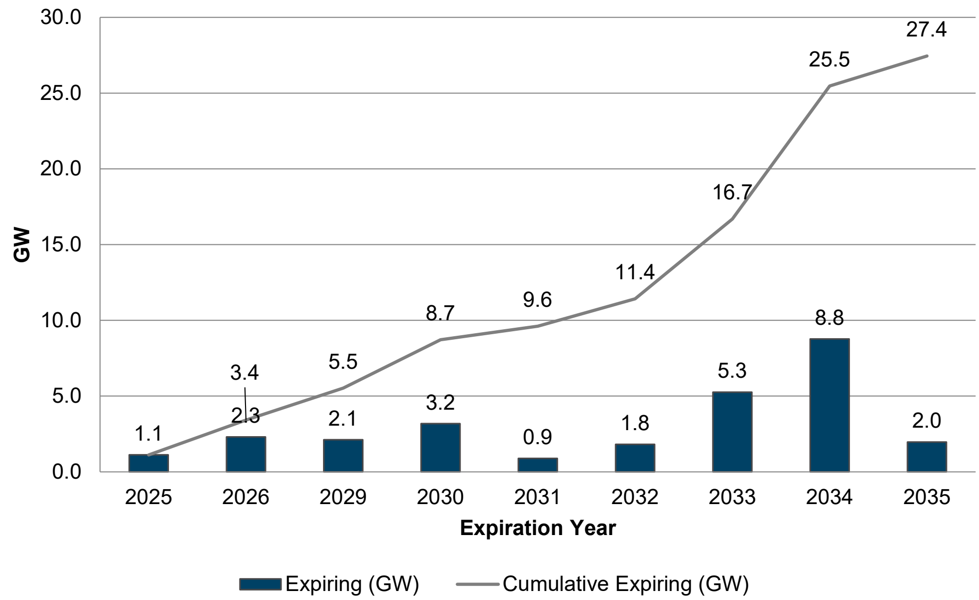
See exhibits 4 and 5, on the following pages.

Exhibit 4
Pain at the Plug
Nuclear Plant-Level Expirations

Reactor	Plant	State	Capacity (GW)	Commissioning	Expiration
Diablo Canyon 2	Diablo Canyon	CA	1.1	1985	2025
Clinton 1	Clinton	IL	1.1	1987	2026
Perry 1	Perry	OH	1.2	1986	2026
Nine Mile Point 1	Nine Mile Point	NY	0.6	1974	2029
Ginna 1	Ginna	NY	0.6	1969	2029
Dresden 2	Dresden	IL	0.9	1969	2029
Comanche Peak 1	Comanche Peak	TX	1.2	1990	2030
H.B. Robinson 2	Robinson	SC	0.8	1970	2030
Monticello 1	Monticello	MN	0.6	1970	2030
Point Beach 1	Point Beach	WI	0.6	1970	2030
Dresden 3	Dresden	IL	0.9	1971	2031
Quad Cities 2	Quad Cities	IL	0.9	1972	2032
Quad Cities 1	Quad Cities	IL	0.9	1972	2032
Comanche Peak 2	Comanche Peak	TX	1.2	1993	2033
Oconee 1	Oconee	SC	0.8	1973	2033
Point Beach 2	Point Beach	WI	0.6	1973	2033
Prairie Island 1	Prairie Island	MN	0.5	1974	2033
Oconee 2	Oconee	SC	0.8	1973	2033
Browns Ferry 1	Browns Ferry	AL	1.3	1973	2033
Cooper 1	Cooper	NE	0.8	1974	2034
Arkansas Nuclear One 1	Arkansas Nuclear One	AR	0.8	1974	2034
Browns Ferry 2	Browns Ferry	AL	1.3	1974	2034
Oconee 3	Oconee	SC	0.9	1974	2034
Calvert Cliffs 1	Calvert Cliffs	MD	0.9	1974	2034
Edwin I. Hatch 1	Hatch	GA	0.9	1974	2034
James A. FitzPatrick 1	FitzPatrick	NY	0.8	1974	2034
Donald C. Cook 1	Donald C. Cook	MI	1.0	1974	2034
Prairie Island 2	Prairie Island	MN	0.5	1974	2034
Brunswick 2	Brunswick	NC	0.9	1974	2034
Millstone 2	Millstone	CT	0.9	1975	2035
Watts Bar 1	Watts Bar	TN	1.1	1996	2035

Source: The Nuclear Energy Institute, William Blair Equity Research

Exhibit 5
Pain at the Plug
U.S. Nuclear Capacity at Risk of License Expiration



Source: The Nuclear Energy Institute, William Blair Equity Research

U.S. energy policy has recently pivoted away from forcing closures in favor of extensions. Over the past five years, 7 plants and 13 reactors have been granted operation license renewals, saving 13 GW of power from leaving the grid.

Exhibit 6
Pain at the Plug
Nuclear Plant Renewals 2020-2025

Nuclear Plant	Reactor Type	Capacity (MW, net)	Renewal Issued	New Expiration	Owner / Operator
Peach Bottom 2 & 3	BWR	2,616	Mar 5, 2020	2053	Constellation / PSEG
Surry 1 & 2	PWR	1,676	May 4, 2021	2052	Dominion Energy
North Anna 1 & 2	PWR	1,934	Aug 28, 2024	2058	Dominion Energy
Monticello 1	BWR	671	Dec 30, 2024	2050	Xcel Energy (NSP-MN)
Oconee 1, 2, 3	PWR	2,743	Mar 31, 2025	2053	Duke Energy
V.C. Summer 1	PWR	973	Jul 1, 2025	2062	Dominion Energy South Carolina
Point Beach 1 & 2	PWR	2,261	Sep 29, 2025	2050	NextEra Energy

Source: NRC, William Blair Equity Research

The last of the low-hanging fruit in the current U.S. nuclear fleet is uprating. GE Vernova has been vocal about this topic and stated that the company has line of sight to an additional 5 GW of power from the 65 reactors under its service contracts. GE is a leading nuclear reactor design company and specialized in the boiling water reactor. Today, 31 reactors use this technology, and GE Vernova still maintains the core reactor service and fueling contracts. The other dominant reactor design is the pressurized water reactor (PWR). Although GE was not responsible for this design, it has PWR service contracts on another 34 reactors through its nuclear reactor joint venture GE-Hitachi and its fuel subsidiary Global Nuclear Fuel.

There are five types of uprating services to increase power output of a nuclear facility.

See exhibit 7, on the following page.

Exhibit 7
Pain at the Plug
Nuclear Reactor Uprate Pathway

Uprate Type	Typical Power Gain (%)	Key Mechanism	Typical Upgrades	Implementation Time	Approx. Cost (USD)	Regulatory Complexity	Example Plants
Measurement Uncertainty Recapture (MUR)	1–2%	Improves feedwater flow measurement accuracy (ultrasonic meters).	Ultrasonic flowmeters, recalibrated instruments, digital control updates.	Months (within refueling outage)	$10–20 million	Low – license amendment required but no major hardware change.	Dresden, Quad Cities, Vermont Yankee
Stretch Uprate	4–7%	Uses design and safety margins; small increases in core flow and turbine efficiency.	Feedwater heaters, turbine controls, flow adjustments, safety margin recalibration.	1–2 years (1–2 outages)	$50–150 million	Moderate – requires system performance and safety margin verification.	North Anna, Turkey Point, Millstone
Extended Power Uprate (EPU)	10–20%	Comprehensive upgrade of core, turbines, pumps, heat exchangers; fuel uprates.	New fuel assemblies, turbine blades, condenser/turbine replacements.	3–5 years	$500 million–$1.5 billion	High – full NRC safety, thermal-hydraulic, and structural review required.	Grand Gulf, Susquehanna, Peach Bottom, Browns Ferry
Fuel and Core Upgrades (LEU+, ATF, burnup optimization)	2–5%	Improved fuel enrichment and materials allow higher core power and longer cycles.	LEU+ (up to 10%), ATF cladding, optimized core designs.	Multi-year (aligns with refueling cycles)	$100–200 million (R&D and fuel development dependent)	High – dependent on NRC rulemaking (LEU+ approval expected ~2028).	Future BWR/PWR upgrades under development (GNF4, Framatome PROtect).
Turbine/Generator & Balance-of-Plant Efficiency Upgrades	1–3%	Improves efficiency of steam cycle components without increasing reactor power.	Low-pressure turbine retrofits, moisture separator reheaters, condenser upgrades.	Months–1 year (during major outage)	$20–100 million	Low – may not require NRC license change if thermal power unchanged.	Many GE Vernova and Siemens Energy service clients across U.S. fleet.

Source: The Nuclear Energy Institute, William Blair Equity Research

Over the past decade, the U.S. has only added 700 megawatts (MW) of capacity through uprating, which raises concern about the 5 GW target. However, we believe the U.S. is in a fundamentally different environment regarding nuclear support and deregulation, and we expect far more uprating projects to begin within the next two years.

Exhibit 8
Pain at the Plug
Nuclear Reactor Uprates 2016-2025

Plant / Unit	Year	Uprate Type	Added MW
Catawba-1	2016	MUR	19.3
Columbia (WNP-2)	2017	MUR	19.3
Browns Ferry-1	2017	EPU	164.7
Browns Ferry-2	2017	EPU	164.7
Browns Ferry-3	2017	EPU	164.7
Peach Bottom-2	2017	MUR	21.7
Peach Bottom-3	2017	MUR	21.7
Hope Creek-1	2018	MUR	20.7
Farley-1	2020	MUR	15.3
Farley-2	2020	MUR	15.3
Watts Bar-2	2020	MUR	16.0
Oconee-1	2021	MUR	14.0
Oconee-2	2021	MUR	14.0
Oconee-3	2021	MUR	14.0
Millstone-3	2021	MUR	19.7

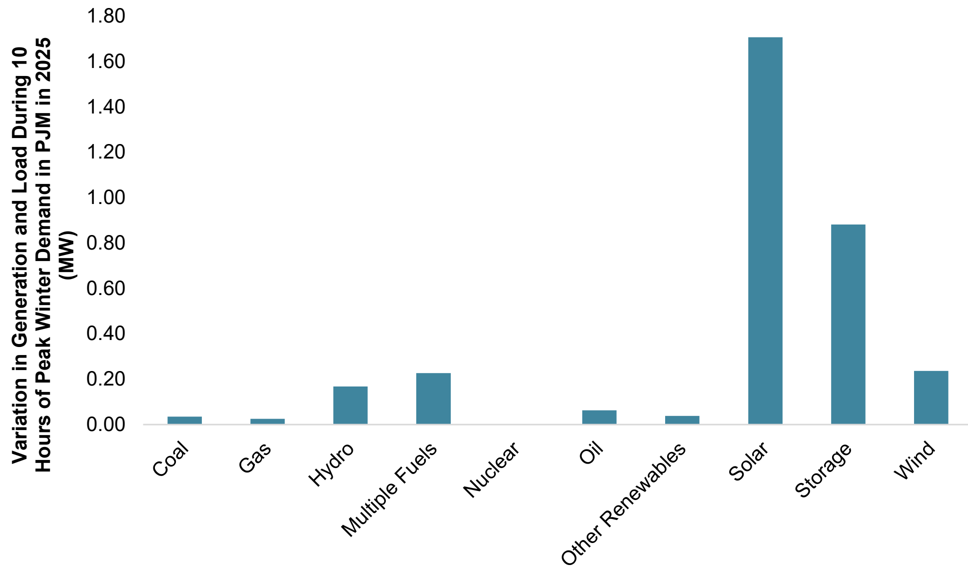
Source: The Nuclear Energy Institute, William Blair Equity Research

Focusing on building out only variable renewable energy has made grid systems across the U.S. vulnerable. PJM is the largest regional transmission operator in the country, and it came very close to blackout during a heat wave at the end of June 2025, prompting then–FERC Chairman Mark Christie to say in a media briefing, "We're simply not building generation fast enough, and we're not keeping generation that we need to keep." The data from this period reinforces what Christie was saying. During the 10 peak hours of 2025 (all of which occurred during a heat wave in June), load peaked at 160,153 MW and generation peaked during the same hour at 162,422 MW. During peak demand hours the variability of solar and wind power production was 23% and 60%, respectively, while the variability of gas generation was 2% and nuclear was less than 1% (see exhibit 9). The winter peak shows a similar story, with solar variability over 160% (see exhibit 10). Grid managers plan for these peak demand hours during the year, and solar and wind are simply unreliable sources during these times.

Exhibit 9

Pain at the Plug

Coefficient of Variation Listed by Resource Calculated Across the Top 10 Peak Demand Hours in the PJM During the Winter of 2025



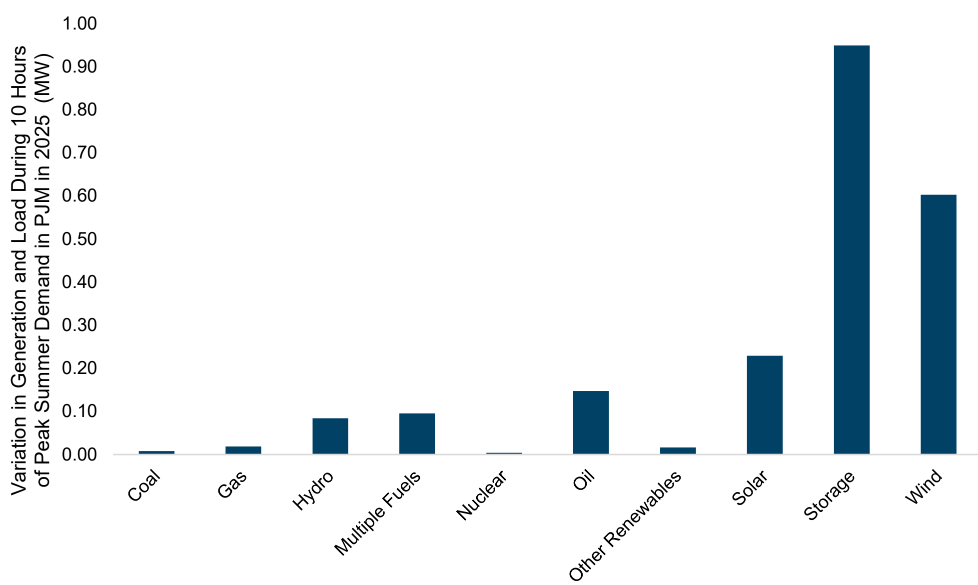
Note: Variation is represented here as the coefficient of variation, which is the standard deviation divided by the average

Source: PJM Data Miner

Exhibit 10

Pain at the Plug

Coefficient of Variation Listed by Resource Calculated Across the Top 10 Peak Demand Hours in the PJM During the Summer of 2025



Note: Variation is represented here as the coefficient of variation, which is the standard deviation divided by the average

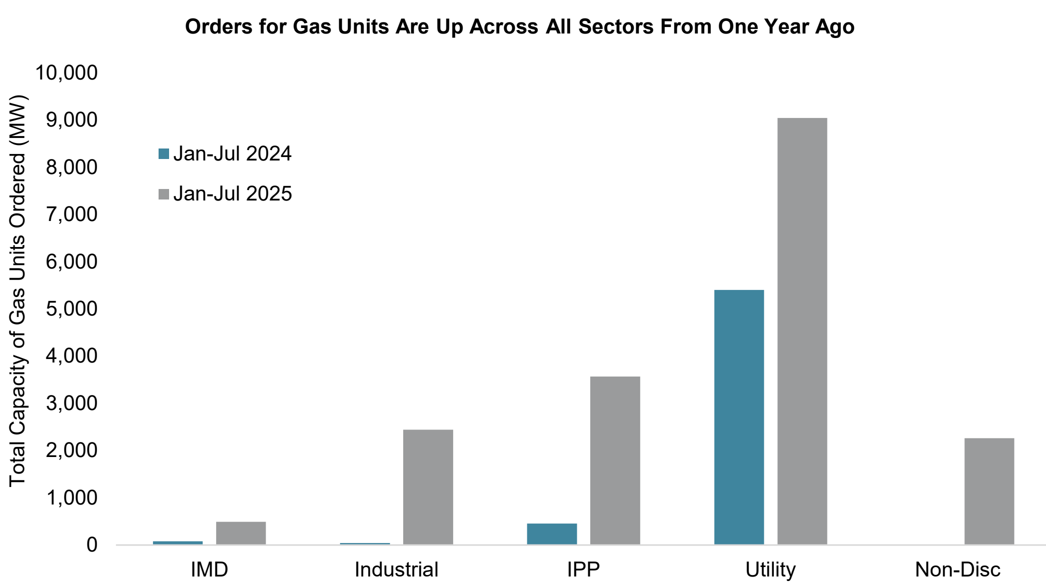
Source: PJM Data Miner

Natural Gas Resurgence

Natural gas offers a high EROI, meaning it delivers significantly more energy than is required to extract, process, and distribute it. This efficiency makes it a vital component of the U.S. energy mix, especially for power generation and heating. The U.S. maintains a critical and stable supply of natural gas through a combination of abundant domestic reserves, advanced extraction technologies like hydraulic fracturing, and a robust pipeline infrastructure. In addition, strategic storage facilities and diversified production regions help buffer seasonal demand spikes. These factors enable the U.S. to meet domestic demand reliably without causing sharp price increases, ensuring energy affordability and security.

As the energy landscape evolves, firm power is quickly becoming synonymous with clean power in today's energy landscape. Affordable, dispatchable energy has always been the backbone of industrial economies, and as the U.S. moves to reshore manufacturing and rebuild its industrial base, access to reliable, on-demand electricity is essential. Utilities and industrial operators recognize this need, which is reflected in a surge of gas turbine orders, reaching decade highs. In the first half of 2025 alone, 41.5 GW of gas generation capacity was ordered, marking a 37% year-over-year increase and the highest six-month total on record. Demand for smaller, flexible generation units is nearing levels last seen during the 2011 fracking boom—underscoring the growing need for firm capacity. Notably, the Americas have surpassed Asia in orders for large, advanced-class turbines for the first time in five years, signaling a strategic shift in regional energy priorities. Jet engine-based "aero" units, valued for their rapid responsiveness, are now sold out in the U.S., not due to lack of demand but supply constraints. Even Baker Hughes, traditionally a smaller player compared to Siemens and GE, has seen a sharp rise in orders, securing the second-highest volume in 2025 thanks to broad-based sector growth. While the future of energy may lean toward renewables and decentralization, the present, and the path to industrial revitalization, still depends on firm, dispatchable power. Without it, efforts to reshore industry and stabilize the grid will face significant challenges.

Exhibit 11
Pain at the Plug
Total Orders for Gas Units (MW) for the First Six Months of 2024 and the First Six Months of 2025



Note: IMD accounts for the oil and gas industry and Non-Disc accounts for the order not being disclosed or attached to the industry or company that was purchasing the unit.

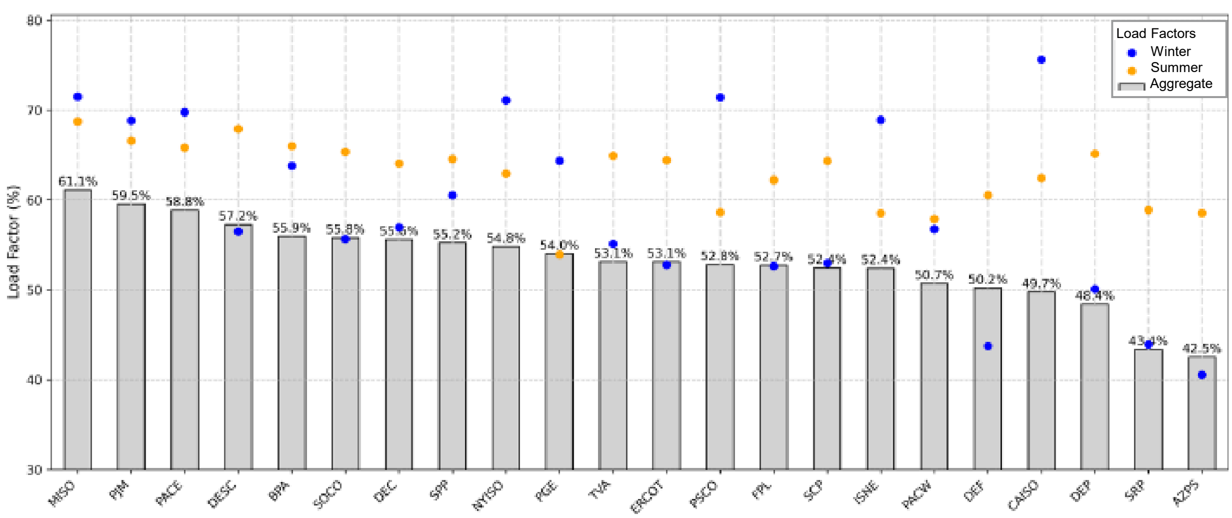
Source: McCoy Power Reports

Batteries With Baseload

Battery energy stationary storage (BESS) is viewed as a costly method to fix the variability of renewables like solar and wind. This drastically underappreciates the potential for BESS tied to our current baseload assets like natural gas and coal. Despite high effective load carrying capacity (ELCC) of 80%, natural gas and coal plants run between 35% and 60% utilization, unlike nuclear at 90%-plus. The U.S. grid is built to handle peak loads; however, grids may require peak output for only one event per year, with the actual demand far below peak for most of the year.

A study from Duke University by Tyler Norris examined the utilization of the balancing authorities in the U.S., and it calculated a range from 43% to 61%. The best grid contained almost 40% headroom, meaning it could produce 40% more power over a year, and the worst grid is capable of 60% more power.

Exhibit 12
Pain at the Plug
Grid Utilization by Balancing Authority

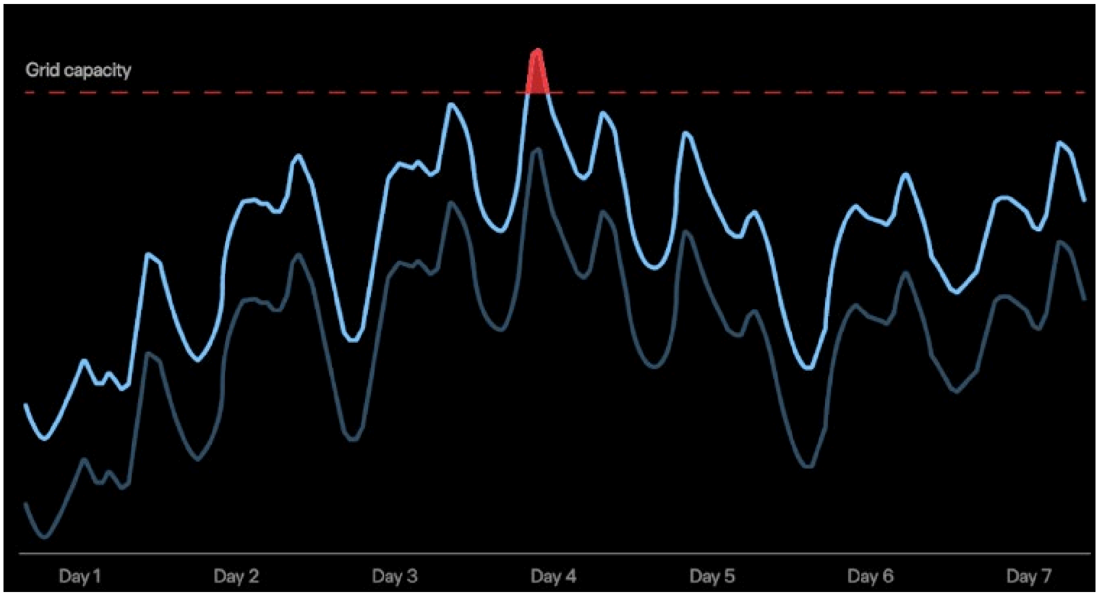


Source: Tyler Norris, Duke University

Historic peak electricity demand was recorded on July 29, 2025, reaching 759 GW, compared with the actual average power production of 326 GW to 463 GW across the measured balancing authorities. We estimate that the 560 GW capacity of natural gas plants operate at a 55% utilization rate on average, or just above 300 GW. If we were to match that to nuclear at 90% utilization, that would bring an additional 196 GW of power online. A similar scenario occurs with coal; if we increase the utilization of the 190 GW capacity, we will bring an additional 95 GW online, thereby increasing our utilization from 40% to 90%. Combined, this is an additional 291 GW, easily addressing the 128 GW load growth forecasts by the Federal Energy Regulatory Commission (FERC) of 128 GW load growth by 2029. The low utilization of our grids is a feature, not a bug, but this leaves considerable headroom in our current installed base to increase total power, if only we could store it. Enter BESS.

Pairing BESS with the installed baseload will allow higher utilization rates, opening almost 300 GW of peak power capacity, easily supplying the additional load growth. During Tesla's recent event introducing the new Megapack and Megablock BESS products, the company highlighted this use-case exactly.

Exhibit 13
Pain at the Plug
Batteries Enable Use of More of the Grid



Source: Tesla

During periods of lower-than-peak demand, baseload generation assets can remain online and store surplus electricity in BESS, which can later be discharged to meet peak demand. At a cost of $250/kWh for a four-hour BESS, deploying 200 GW (800 GWh) of storage to support 90% utilization of the natural gas fleet would require an estimated $200 billion in capital investment. In contrast, meeting the same demand by building additional natural gas plants at $2,000/kW would cost twice as much—roughly $400 billion. Moreover, BESS costs are steadily declining, while the cost of combined cycle gas turbines has doubled, with manufacturing capacity sold out through 2028. Tesla is addressing both cost and availability by tripling its Megapack production from 40 GWh to 120 GWh in 2026.

Integrating BESS with existing assets enhances asset utilization, thereby increasing revenue potential and spreading fixed costs over a larger energy output—ultimately improving return on invested capital. In addition, the operational efficiency of natural gas and coal plants declines with frequent start-stop cycles, which are more common in grids with high renewable penetration. These cycles reduce turbine inlet temperatures and lower Carnot efficiency. By enabling continuous turbine operation, BESS helps maintain optimal inlet temperatures, boosting efficiency from about 45% to 60% (improving heat rate from about 7,500 BTU/kWh to roughly 6,500 BTU/kWh).

Locating BESS at existing power plant sites allows for the reuse of critical infrastructure, such as substations, transformers, switchgear, and transmission and distribution networks, significantly reducing development complexity and cost. This is especially important given the current strain on engineering, procurement, and construction capacity caused by the rapid expansion of data centers, which has led to multiyear lead times for key equipment. We estimate that integrating BESS with our existing baseload generation could address a substantial portion of the upcoming load growth inflection at up to 50% lower capital expenditure, while delivering power several years sooner than new-build natural gas or nuclear facilities.

Pillar II – Market Design That Prices Reality

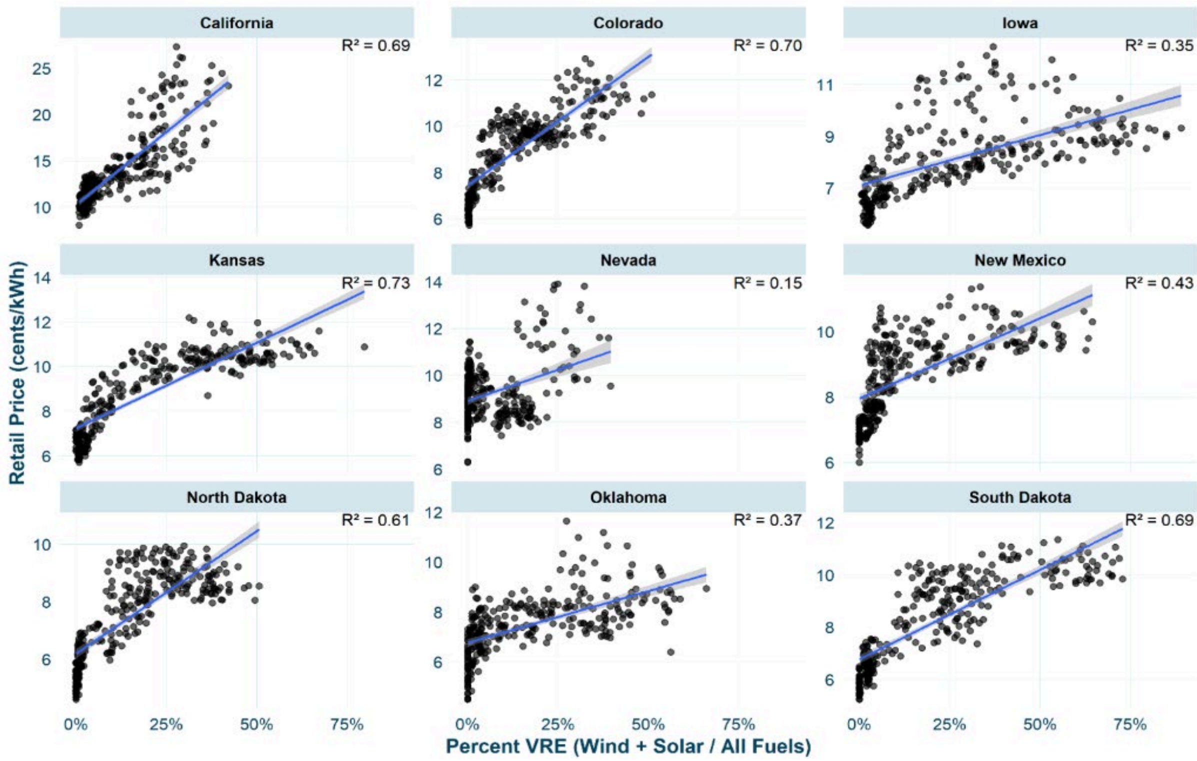
We believe it is essential that energy market incentive schemes reward reliability, ensuring that power providers who deliver consistent, on-demand electricity, especially during peak demand or grid stress, are appropriately compensated for the critical role they play in maintaining system stability and public confidence. To support this, we advocate for a shift from traditional renewable energy credits toward a firmness standard that incentivizes utilities to plan for reliable generation. Implementing an ELCC-based accreditation system would enable payments and incentives to be tied to a power plant's proven ability to perform under stress, rather than its nameplate capacity. In addition, introducing reliability pricing adders, such as a locational marginal reliability component layered onto locational marginal prices, would help appropriately value grid attributes like scarcity and inertia, ensuring backup and system resilience are financially recognized. Lastly, we believe it is time to reevaluate deregulated market structures, as evidence shows that electricity prices in deregulated regions often exceed those in regulated markets, raising questions about long-term affordability and efficiency.

The Firmness Standard Is Essential

The objective of power generation is not merely to produce electricity, but to deliver high-EROI power reliably to society. When variable renewable assets like wind and solar introduce additional system costs, such as backup generation, grid upgrades, or curtailment, those costs must be transparently accounted for to accurately reflect the total cost of delivering dependable, profitable energy. Assigning these costs to the point of generation enables true cost accounting, in our view. Without a full end-to-end assessment of integration costs, we risk compromising grid reliability and resilience.

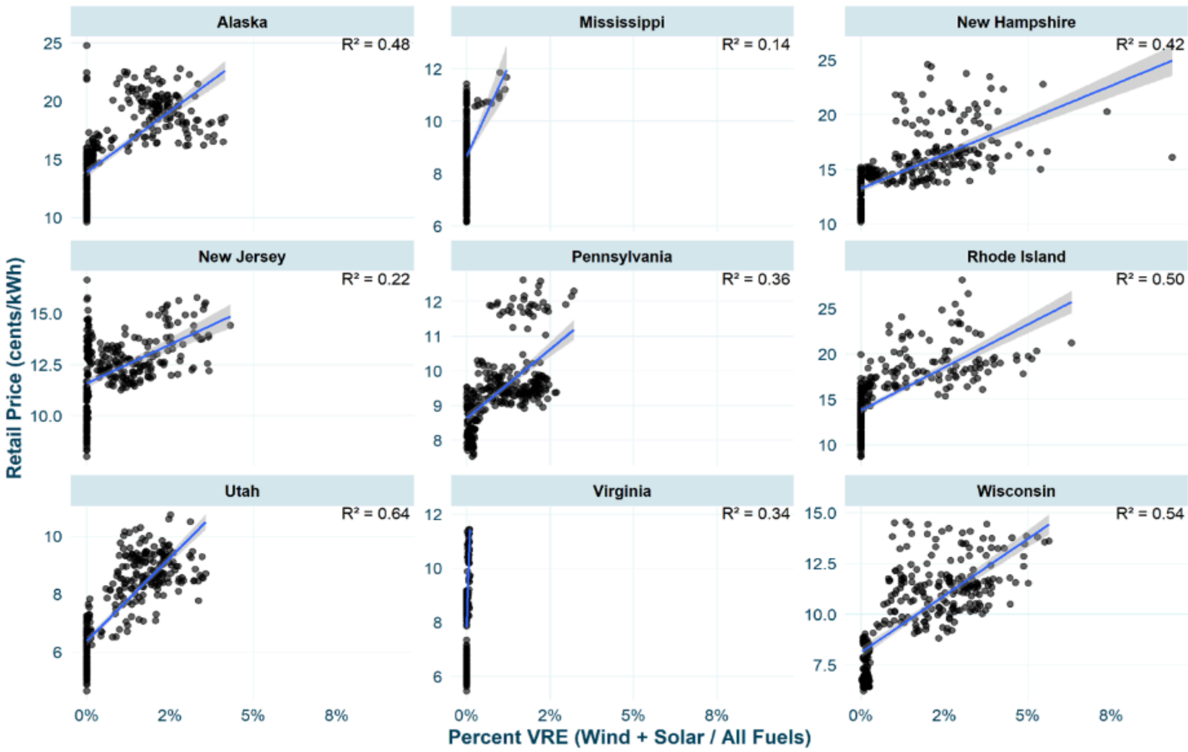
Beyond reliability concerns, the expansion of variable renewable energy (VRE) has also contributed to rising electricity rates nationwide. Across both regulated and deregulated markets, and regardless of political affiliation, states with higher levels of VRE consistently experience higher retail electricity prices. These increases may stem from factors such as transmission investments, renewable portfolio standards, or other policy-driven costs. The key takeaway is that regardless of the specific drivers, retail electricity prices tend to rise in tandem with greater wind and solar penetration (see exhibit 14, on the following page). This trend is evident in states not only with mature VRE deployment, but also beginning their transition (see exhibit 15, on page 19).

Exhibit 14
Pain at the Plug
Retail Price vs. VRE Share - Top 9 U.S. States by Most Recent VRE (%)



Source: Energy Information Administration

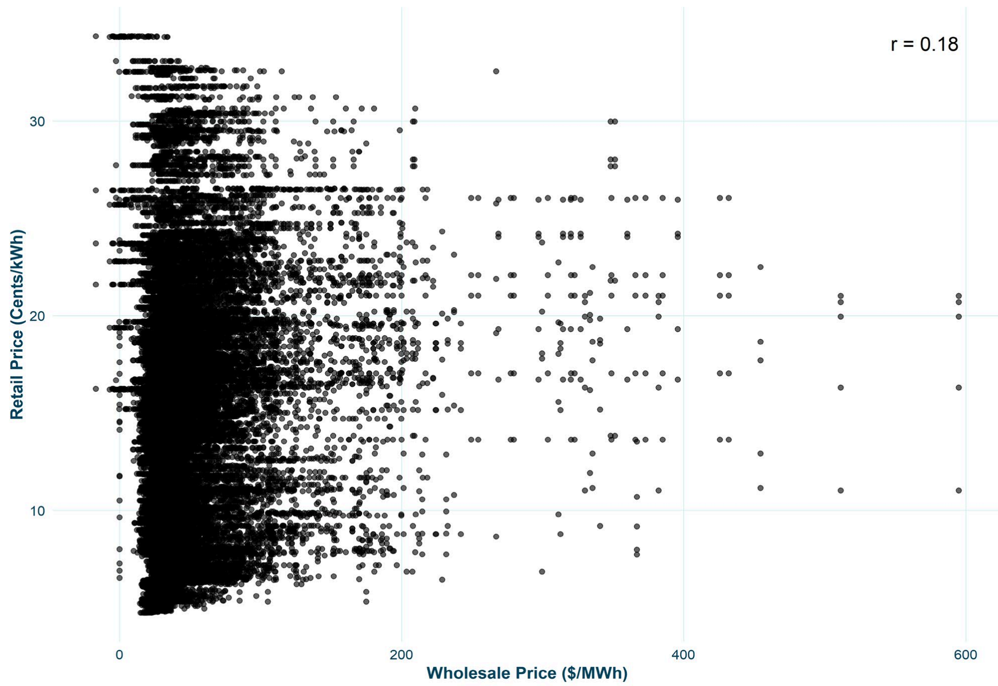
Exhibit 15
Pain at the Plug
Retail Price vs. VRE Share - Bottom 9 U.S. States by Lowest VRE (%)



Source: Energy Information Administration

Grid balancing costs are often excluded from wholesale electricity prices, making those prices increasingly unreliable indicators of what consumers will pay (see exhibit 16, on the following page). Over the past decade, while average retail electricity prices have steadily increased, wholesale prices have remained relatively flat (see exhibit 17, on the following page). This divergence highlights a critical issue: wholesale prices no longer reflect the true costs of delivering reliable electricity. As a result, relying solely on wholesale market signals can obscure the financial realities of maintaining a resilient and dependable grid.

Exhibit 16
Pain at the Plug
Wholesale vs. Retail Electricity Prices (Deregulated States)



Note: Wholesale power prices vs. retail power prices averaged across states with deregulated electricity

Source: Energy Information Administration

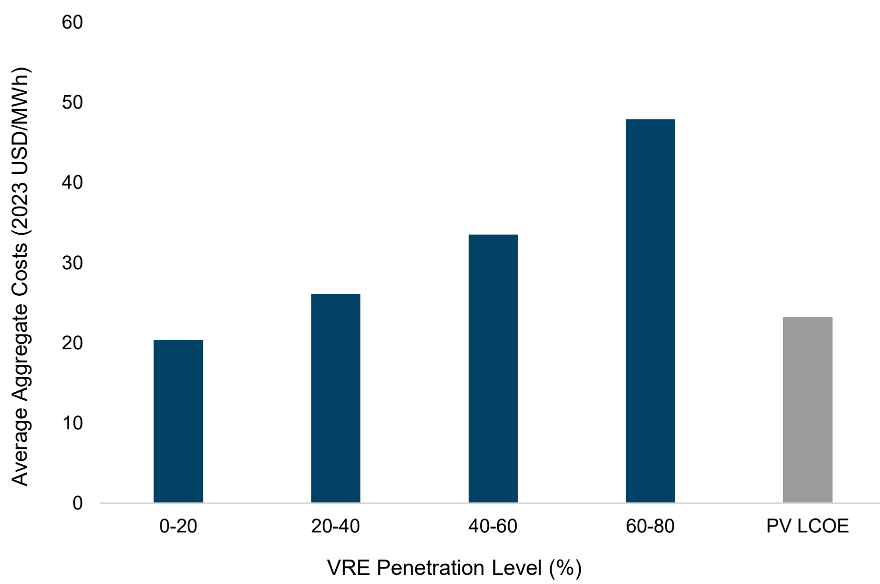
Exhibit 17
Pain at the Plug
Wholesale vs. Residential Retail Electricity Prices

Note: Residential retail electricity prices and average wholesale prices across deregulated states

Source: Energy Information Administration

Similarly, the levelized cost of electricity (LCOE) is becoming an increasingly inadequate metric for evaluating generation technologies. While LCOE has long served as a benchmark for comparing the economic viability of different energy sources, it fails to capture many of the new and significant costs associated with delivering reliable electricity. Lazard's LCOE analysis excludes key factors such as transmission queue reform, network upgrades, congestion, curtailment, and other integration-related expenses. As a result, LCOE tends to align more closely with wholesale power prices than with the actual costs of dependable electricity delivery. We believe this disconnect underscores the need for more comprehensive cost metrics that reflect the full system impact of VRE.

Exhibit 18
Pain at the Plug
Aggregate Costs vs. LCOE for Variable Renewable Energy Penetration



Source: Heptonstall and Gross 2021 and William Blair Equity Research

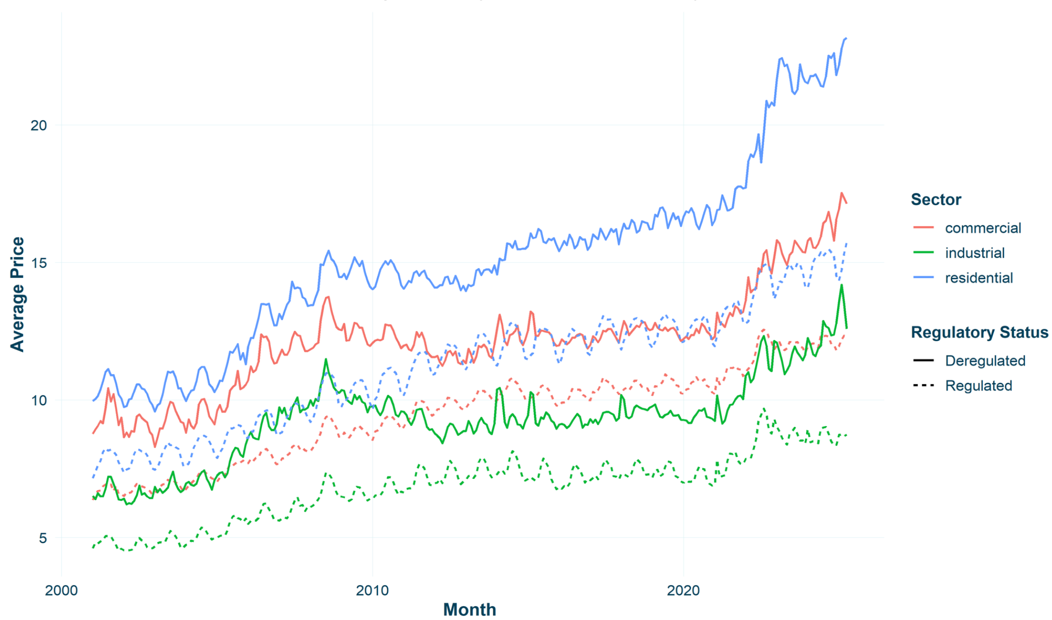
Rethinking the Regulation of Energy Markets

The deregulation experiment in general seems to be an abject failure. The deregulation of the electricity sector, initiated by the Energy Policy Act of 1992, was intended to harness market competition to lower wholesale electricity prices and, in turn, reduce retail costs for consumers. However, more than three decades later, the results have diverged sharply from those expectations. Retail electricity prices in deregulated states have consistently been higher than in regulated ones, and since 2020, they have risen roughly 20% faster (see exhibits 19 and 20). Even more telling is the complete lack of correlation between wholesale and retail prices; while wholesale rates have remained flat in deregulated markets over the past decade, retail prices continue to climb. This suggests that deregulated markets introduce additional layers of profit-taking and incentive structures that do not necessarily benefit end-users. For example, if a developer builds a solar farm under a PPA, its incentive is to maximize generation to fulfill contractual obligations and secure returns, regardless of whether that generation aligns with grid needs or leads to the lowest electricity costs for consumers. This dynamic reflects a broader misalignment in deregulated markets, where individual actors optimize for profit rather than systemwide efficiency or affordability.

There is a growing recognition of the value of regulated utilities that manage generation as a coordinated portfolio, including firm, baseload energy sources. Centralized oversight enables long-term planning and strategic investment in capital-intensive infrastructure, such as grid modernization and resilient generation assets, because costs can be spread over time through advanced rate design that protects customers while enabling growth. This model also allows for strategic integration of diverse energy sources, ensuring a stable supply while maintaining affordability. As the energy transition accelerates, the ability to align infrastructure development with public policy goals, rather than short-term market incentives, makes the case for a return to a more centralized regulatory model increasingly compelling.

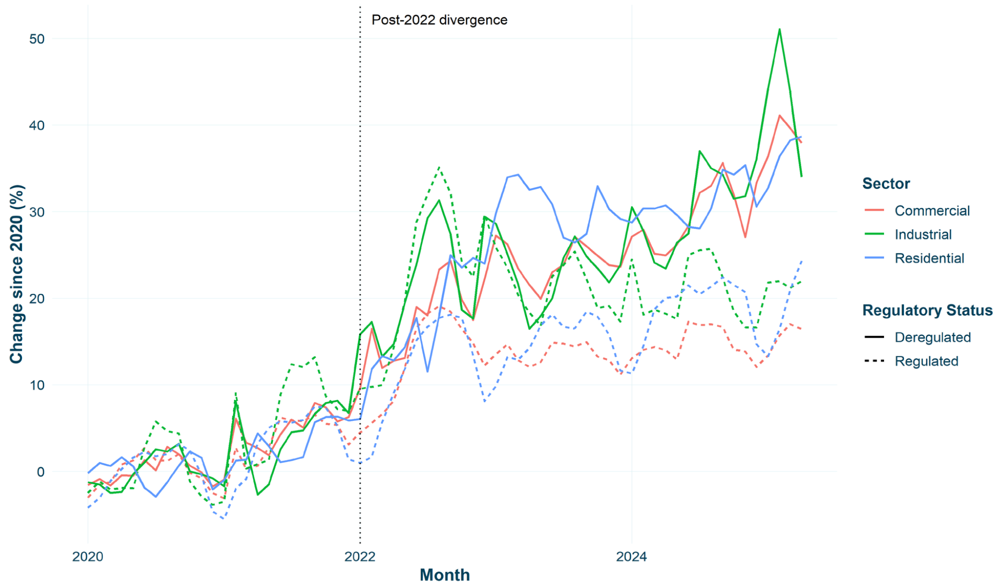
Regulated markets can serve as the stabilizing backbone that enables a smoother, more equitable transition to competitive energy structures. By enabling strategic investment and spreading costs over time, regulated markets can modernize aging infrastructure, strengthen transmission networks, and ensure a resilient, affordable energy supply. These foundational improvements not only benefit consumers directly, but also create the conditions necessary for a more functional and efficient deregulated market in the future. While the long-term trajectory of energy markets is likely to favor deregulation, driven by innovation, decentralization, and consumer choice, regulated markets offer the structure and stability needed to get there. In this way, they act as a bridge: reinforcing the grid, aligning incentives with public interest, and laying the groundwork for a competitive energy future that is both reliable and equitable.

Exhibit 19
Pain at the Plug
Average Monthly U.S. Retail Electricity Prices



Note: Average monthly U.S. retail electricity prices, averaged across all states filtered by regulatory status. The data was then further separated by sector
Source: Energy Information Administration

Exhibit 20
Pain at the Plug
Change in U.S. Retail Electricity Prices Since 2020



Note: Average monthly U.S. retail electricity prices, averaged across all states filtered by regulatory status. The data was then further separated by sector
Source: Energy Information Administration

Energy Reliability and Affordability in a Data-centric World

Reliability and price are already driving data center siting. Data center construction in the U.S. is surging to unprecedented levels, driven by cloud computing and recent advances in AI. As described in our report The Power Behind Artificial Intelligence, each ChatGPT query is anywhere from 10 to 450 times more energy intensive than a standard Google search. According to EPRI, data centers are projected to account for between 4.6% and 9.1% of U.S. electricity demand by 2030, depending on growth trajectories. As a result, power availability and reliability have become critical factors in site selection for new facilities. Modern data centers operate with power usage effectiveness ratios near 1.55, with some hyperscale sites achieving as low as 1.08. On the other hand, outages are extremely costly, averaging $7,500 per minute of downtime, making uninterrupted power and robust cooling essential design priorities. Historically, U.S. data center capacity has been concentrated in a few regions, notably northern Virginia's Ashburn hub, but construction is now expanding nationwide. Data compiled by William Blair show new facilities announced in states such as Texas, Tennessee, Wisconsin, Georgia, North Dakota, New Jersey, and several undisclosed locations, totaling 5,744 MW of planned capacity.

The cost of powering a data center can vary dramatically depending on its location. Operating a 100 MW facility in California would cost more than three times as much as in one of the nation's least expensive power markets. In 2024, California's industrial electricity rate averaged 21.63 cents per kilowatt-hour, or about $152 million annually if operated continuously. By contrast, Texas, under its ERCOT system, maintained an industrial rate of just 6.25 cents per kilowatt-hour, or roughly $55 million per year for the same operation. Choosing California over Texas would therefore add more than $100 million annually in electricity expense alone.

The difference lies not only in ERCOT's energy-only market design but in its intrastate structure and physical geography. Because ERCOT's grid is contained entirely within Texas, it avoids the federal transmission tariffs and multi-state cost allocations imposed on other independent system operators. Transmission and distribution infrastructure is built and recovered locally, spreading a far smaller cost base across an enormous industrial load. Moreover, Texas co-locates much of its generation with its natural-gas reserves and pipeline infrastructure, minimizing fuel transport costs and enhancing reliability. This combination of local control, short supply chains, and abundant low-cost fuel creates a structural cost advantage that places ERCOT's delivered electricity rates several standard deviations below those of other deregulated markets.

While critics argue that the 2021 Winter Storm Uri costs have yet to be fully absorbed, the $2.9 billion in securitized recovery (minuscule relative to the more than $195 billion in broader economic losses) adds only a fraction of a cent per kilowatt-hour. In statistical and economic terms, the impact on ERCOT's industrial base remains immaterial, reinforcing why Texas continues to anchor the nation's lowest-cost and fastest-growing corridor for energy-intensive digital and industrial investment.

Exhibit 21
Pain at the Plug
Projected Annual Electricity Costs for a 100 MW Data Center – Assuming an 80% Utilization

State	Average Annual Industrial Electricity Price (cents/kWh)	Annual Electricity Cost ($)	Regulatory Status
California	21.63	$151,583,040	deregulated
Rhode Island	19.68	$172,411,400	deregulated
Massachusetts	18.12	$158,767,700	deregulated
Connecticut	17.32	$151,759,700	deregulated
New Hampshire	16.22	$142,043,400	deregulated
Texas*	6.25	$54,764,600	deregulated
Tennessee	6.21	$54,370,400	regulated
Oklahoma	5.77	$50,559,800	regulated
Louisiana	5.59	$48,983,000	regulated
New Mexico	5.52	$48,369,800	regulated

Note: Projected annual electricity costs for a 100 MW data center, assuming continuous operation and industrial electricity rates, for the top five and bottom five states ranked by average industrial electricity price in 2024. Data excludes Hawaii and Alaska. *Texas has a very different market structure than other deregulated states and should be considered an outlier in this assessment of regulated vs. deregulated markets.

Sources: William Blair Equity Research

Exhibit 22
Pain at the Plug
Planned Data Centers and Computing Facilities

Owner & Partners	Facility Name	City	Estimated Completion	Estimated Capacity (MW)	Investment Size	Chip Architecture
ExxonMobil	Discovery 6	Spring, TX	2025 - 1H	NA	NA	NVIDIA GH200
OpenAI & Oracle	Stargate Stargate (Expansion)	Abilene, TX	2025 - Q4 2027 - Q4	240 600	NA	NVIDIA GB300
Oracle	Oracle OCI Supercluster	TBD	2025 - Q4	262	NA	NVIDIA B200
Applied Digital & CoreWeave	Polaris Forge 1	Ellendale, ND	2025 - Q4 2026 - Q3 2027 - Q2	100 150 150	$7 billion in lease revenue	NVIDIA GB200
Microsoft & OpenAI	Fairwater Fairwater (Expansion)	Mount Pleasant, WI	2026 - Q1 2028 - Q4	750 333	$3.3 billion $4 billion	NVIDIA GB200
xAI	Colossus 2	Memphis, TN	2026 - Q4	2,202	$20 billion	NVIDIA GB200
Nebius AI & Microsoft	TBD	Vineland, NJ	2026 - Q4	300	$17.4 billion	NVIDIA GB200
Tesla	Cortex 2.0	Austin, TX	2026 - Q4	140	$5 billion	NVIDIA H100 SXM5 80GB
CoreWeave	TBD - Phase 1 TBD - Phase 2	Lancaster, PA	2026 - Q4 2028 - Q4	100 200	$6 billion	NVIDIA GB200 NVIDIA GB300
Amazon Web Services	TBD	Butts & Douglas Counties, GA	2027 - Q4	917	$11 billion	NVIDIA GB200 NVIDIA GB300
OpenAI, Oracle & SoftBank	Stargate (Tranche 2)	Shackelford County, TX Doña Ana County, NM Milam County, TX Lordstown, OH Abilene, TX	2028 - Q4	1,100	$500 billion	NVIDIA GB200
OpenAI & NVIDIA	TBD	TBD	2028 - Q4	10,000	$100 billion	NVIDIA GB200 NVIDIA GB300
Fermi Project	HyperGrid	Amarillo, TX	2032 - Q4	11,000	NA	NVIDIA GB200

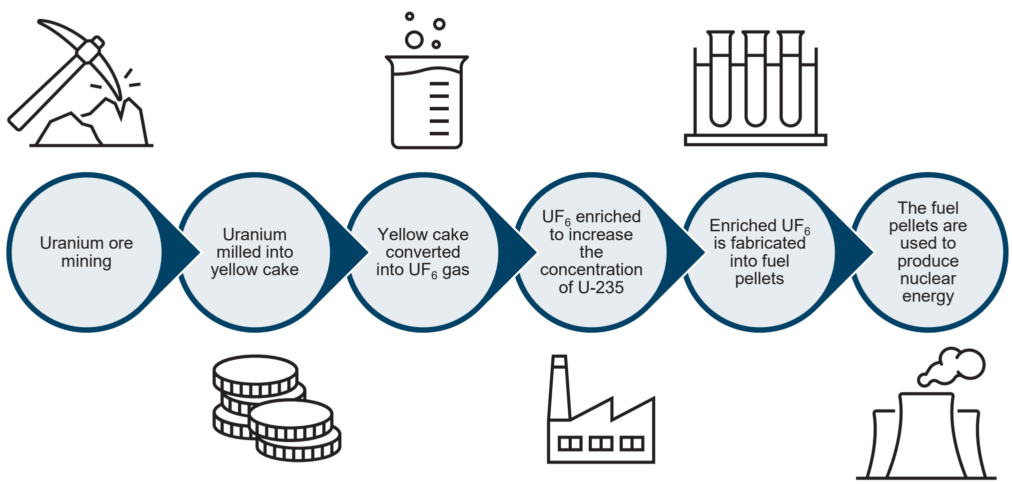
Sources: Company reports and William Blair Equity Research

Pillar III – Energy Resilience Will Secure America

Strategic Fuels and Security

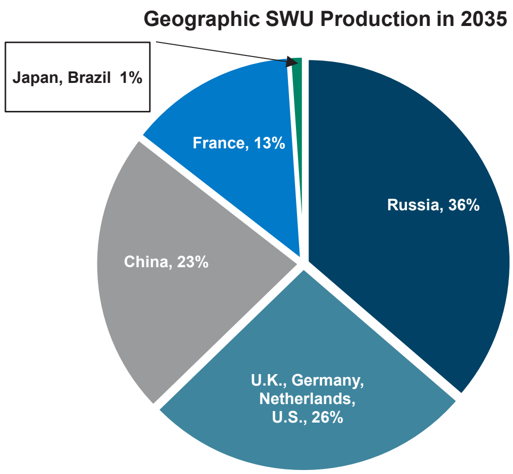
The nuclear fuel supply chain relies heavily on a limited number of countries that provide both uranium ore and enrichment capabilities. Uranium reserves are distributed globally, but about two-thirds of the world's uranium production originates from mines in Australia, Kazakhstan, and Canada. After extraction and refinement, uranium must be enriched, which is a process carried out by only nine countries: Russia, China, the United Kingdom, Germany, the Netherlands, the U.S., France, Japan, and Brazil. These nine countries all possess enrichment capacity, but the global nuclear fuel cycle remains heavily reliant on Russia for its supply of separative work units (SWU), a key measure of uranium enrichment capacity. Currently, Russia provides about 44% of the world's SWU, although this share is projected to decline to 36% by 2035 as China expands its enrichment capabilities. China's contribution is expected to grow from 14% in 2025 to 23% by 2035, positioning it as a major player in the market.

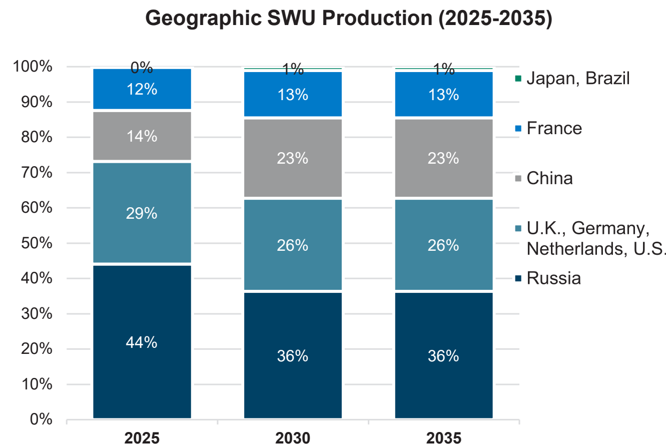
Exhibit 23
Pain at the Plug
Nuclear Fuel Cycle



Sources: Company reports and William Blair Equity Research

Exhibit 24
Pain at the Plug
Geographic Breakdown of SWU Production

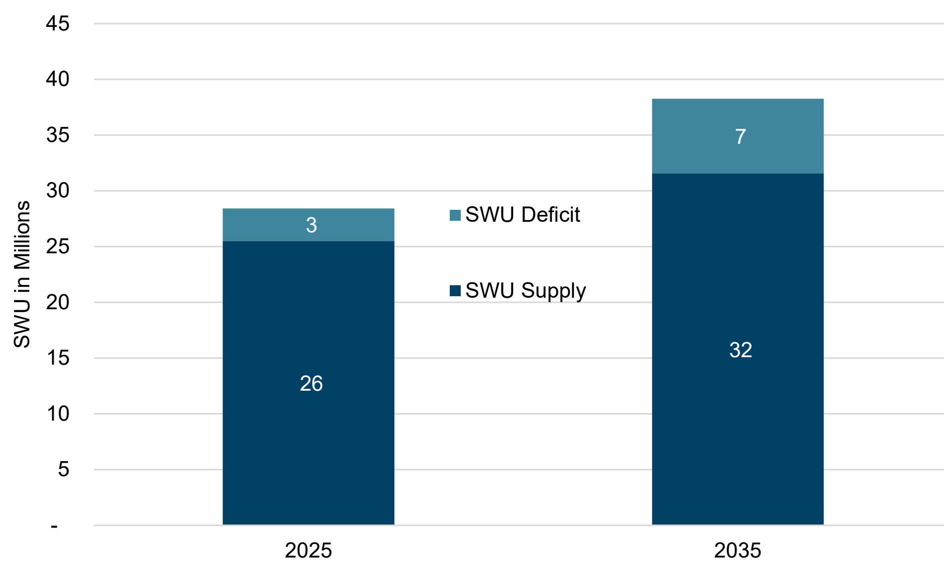




Sources: Company reports and William Blair Equity Research

While global SWU capacity could exceed demand if all planned developments are realized, geopolitical tensions are likely to constrain actual supply. Russian enrichment services, primarily provided by Rosatom and its subsidiary TENEX, are subject to import quotas under the Russian Suspension Agreement (RSA), which regulates the entry of Russian uranium products into the U.S. Although the RSA currently permits U.S. companies to distribute Russian-enriched uranium, the passage of the Import Ban Act in 2024 prohibited imports from Russian producers starting August 2024. The U.S. Department of Energy (DOE) retains the authority to issue waivers that allow uranium imports to fulfill existing contractual obligations. For instance, Centrus Energy received waivers enabling it to deliver Russian uranium to customers through 2025. However, the DOE has not clarified whether waivers will be extended beyond this year. In parallel, Russia has imposed its own restrictions under the Russian Decree, which bans uranium exports to the U.S. through December 2025. TENEX has obtained special export licenses to complete deliveries for 2024 and 2025 and has expressed interest in securing additional licenses, although future approvals remain uncertain.

Exhibit 25
Pain at the Plug
SWU Supply and Demand Deficit – Excluding China and Russia



Sources: Company reports and William Blair Equity Research

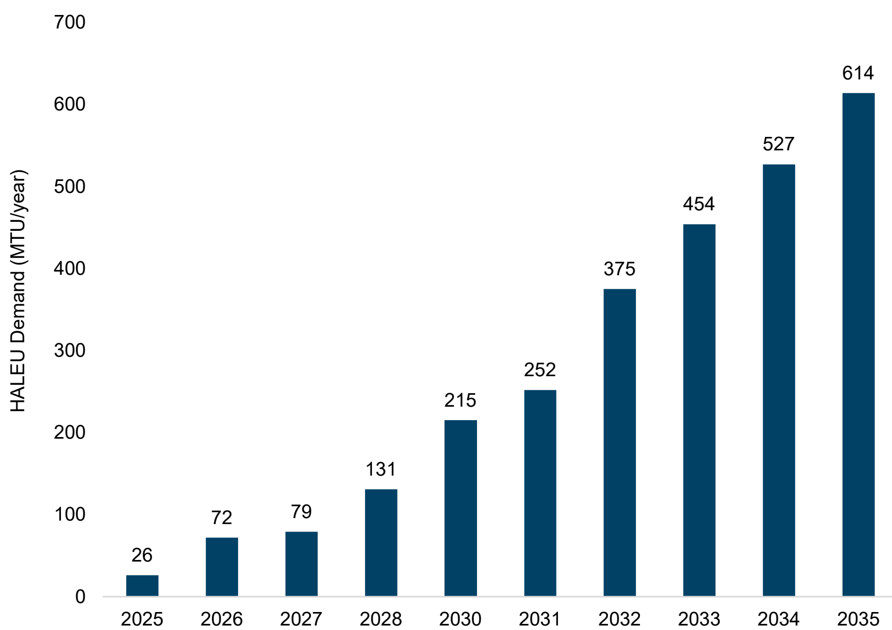
Continuing geopolitical instability, particularly the war in Ukraine and strained U.S.-China relations, could disrupt supply contracts and further complicate the global enrichment landscape. Our analysis indicates that with current geopolitical conditions, the U.S. will need to replace approximately 4 million SWU previously sourced from Russia, representing nearly 30% of the enrichment capacity required to sustain its commercial nuclear power fleet. The U.S. should accelerate the development of its domestic enrichment capacity to ensure energy security, and this replacement capacity should be both domestic and American-owned. Centrus Energy emerges as the most viable candidate, followed by BWX Technologies, both of which meet these criteria. Additional capacity could come from domestic expansions by Urenco and Orano; however, these companies are owned by foreign entities, and this introduces strategic considerations.

The projected buildout of small modular reactors will also increase the demand for high assay low-enriched uranium (HALEU). The market for HALEU is still developing, but demand is expected to grow significantly over the next decade as advanced nuclear reactors are deployed globally. Currently, Russia and China are the only countries with commercial-scale HALEU supply chains. However, because of national security concerns, the U.S. is unlikely to rely on Russian or Chinese HALEU to fuel its advanced reactor fleet. The U.S. currently produces limited quantities of HALEU at the Idaho National Laboratory for national security purposes. To ensure energy independence, the U.S. is making substantial investments to develop a domestic HALEU supply chain. The DOE is leading this effort through the HALEU Availability Program, established under the Energy Act of 2020. This initiative allocates HALEU produced from DOE-owned assets to U.S. reactor developers to stimulate commercial production. In April 2025, the DOE made its first round of conditional HALEU supply commitments to five U.S. reactor developers: TRISO-X, TerraPower, Kairos Power, Radiant Industries, and Westinghouse Electric Company. These companies may begin receiving HALEU as early as fall 2025. The DOE aims to distribute a total of 21 metric tons of HALEU to advanced reactor developers by June 2026.

To build a robust supply chain, the DOE is also partnering with private industry. Centrus Energy and Orano are actively working to expand their enrichment capabilities to meet both government and commercial needs. Centrus holds a license from the Nuclear Regulatory Commission license to produce HALEU and has already delivered about 920 kilograms to the DOE. Orano plans to scale its enrichment operations to support HALEU production above 6% by 2030.

While these efforts are promising, the primary challenge remains the significant upfront investment required to establish a commercial-scale HALEU supply chain. The Nuclear Energy Institute estimates that more than $500 million in capital is needed for enrichment and deconversion infrastructure. Investment is unlikely to materialize without a steady customer base; however, reactor developers need HALEU to validate their technologies. This dilemma highlights the critical role of continued DOE support in bridging the gap. We believe Centrus and Orano are well positioned to lead the development of a domestic HALEU supply chain, especially if projected demand materializes as expected.

Exhibit 26
Pain at the Plug
HALEU Demand Forecast



Sources: Centrus Energy, Nuclear Energy Institute, and William Blair Equity Research

Standardized Nuclear Reactor Development

The U.S. must standardize its nuclear reactor development process to limit cost overruns and increase the viability of nuclear generation. The status of U.S. nuclear development projects can be analyzed through a comparison with Chinese development projects. China currently operates 58 nuclear reactors generating approximately 54 GW, representing 15% of global nuclear capacity, ranking third behind the U.S. and France. However, China's growth trajectory is unmatched; 30 reactors are under construction, with an additional 36 approved and funded. China previously contracted Westinghouse to build four AP1000 reactors, all of which are now operational. Notably, Vogtle Units 3 and 4 in Georgia and Sanmen Units 1 and 2 in Zhejiang began construction within a month of each other. Yet the outcomes diverged sharply.

Exhibit 27
Pain at the Plug
Operational Comparison: Vogtle vs. Sanmen Nuclear Plants

Metric	Vogtle Units 3 and 4	Sanmen Units 1 and 2
Plant Name	Alvin W. Vogtle Electric Generating Plant	Sanmen Nuclear Power Station
Reactor Design	Westinghouse AP1000 Generation III+	Westinghouse AP1000 Generation III+
Power Output (MW)	2,234	2,386
Total Cost (USD)	$34 billion	$8.08 billion
Cost per kW (USD)	$15,219	$3,384
Construction Start	March 2009 (Unit 3), November 2009 (Unit 4)	April 2009 (Unit 1), December 2009 (Unit 2)
Commercial Operation	July 2023 (Unit 3), April 2024 (Unit 4)	September 2018 (Unit 1), November 2018 (Unit 2)
Construction Time	~15 years (2009–2024)	~9 years (2009–2018)

Sources: Company reports and William Blair Equity Research

Vogtle's cost was 4 times higher and construction time was nearly double that of Sanmen. While lower labor and material costs in China contribute to this disparity, the more significant factor is the contrast in regulatory environments. China's streamlined approval processes and centralized support have enabled rapid deployment of advanced technologies. China has since developed its own Generation III+ reactors, Hualong One and Two, with construction costs reduced to $2,000/kW and build times shortened to four years. These achievements underscore the potential of a coordinated regulatory framework, government backing, and a proactive approach to innovation in nuclear energy development.

To remain competitive in nuclear energy development, the U.S. must reevaluate its regulatory framework, which has become a significant driver of cost and delay in reactor construction. Streamlining licensing procedures, reducing bureaucratic redundancies, and adopting risk-informed approaches, without compromising safety, could dramatically improve project economics. Emulating aspects of China's centralized and expedited approval process while maintaining transparency would enable faster deployment of advanced reactor technologies. A more agile regulatory environment, coupled with federal support and clear market signals, is essential for revitalizing domestic nuclear infrastructure and achieving energy security goals.

Gas-to-Power Value Chain

The gas-to-power value chain encompasses the extraction, transportation, and processing of natural gas for use in electricity generation. The value chain consists of five primary stages:

1. **Upstream:** where gas is explored and extracted out of the ground;

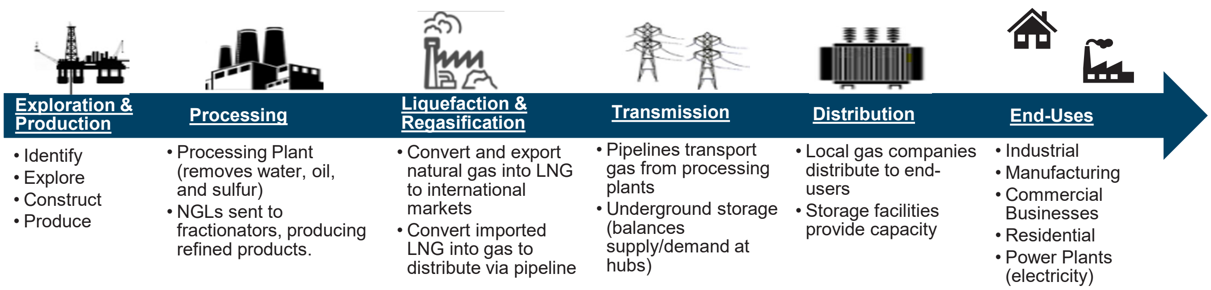
2. **Midstream:** which consists of processing, storage, and long-distance transportation via pipelines or liquified natural gas (LNG) tankers;

3. **Downstream:** the final delivery of the production through low-pressure pipes to businesses including power plants, industrial and manufacturing facilities, commercial users, and residential customers; and

4-5. **Transmission and distribution:** which play a critical role in ensuring reliable access for end-users.

The U.S. currently operates over 3 million miles of natural gas pipelines, including about 2.5 million miles of local distribution lines and 300,000 miles of interstate and intrastate transmission pipelines. These networks enable the natural gas produced in major basins, such as the Marcellus, Permian, Appalachia, and Haynesville, to reach high-demand centers across the U.S., and the Gulf Coast for LNG exports.

Exhibit 28
Pain at the Plug
Natural Gas Supply Chain



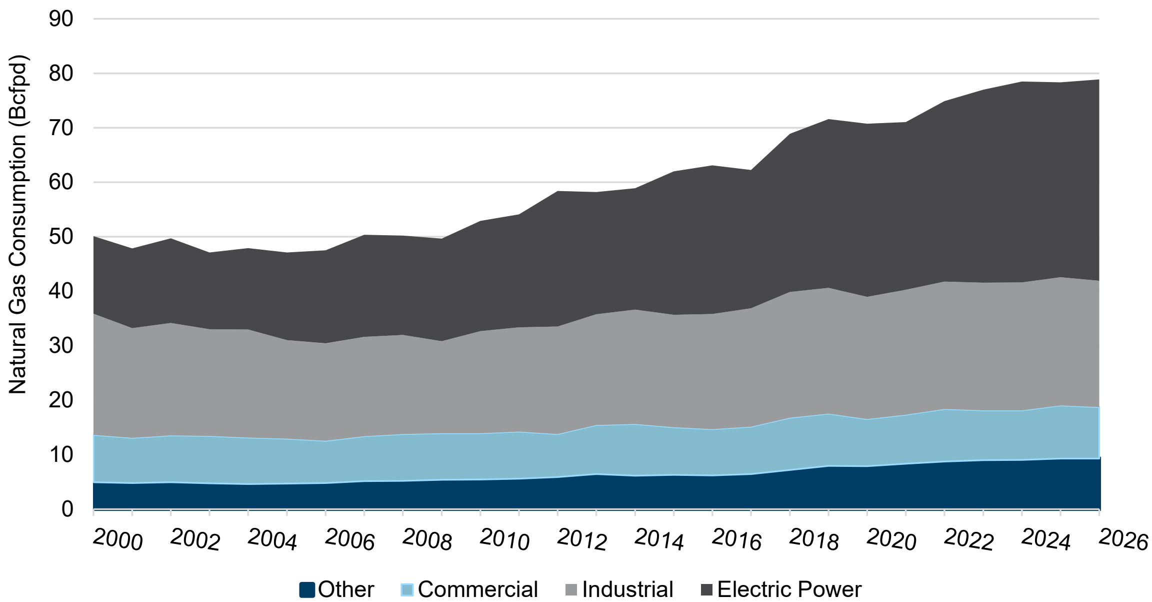
Source: William Blair Equity Research

Insatiable Natural Gas Appetite

The U.S. Energy Information Administration (EIA) estimates that total U.S. natural gas demand will increase this year to a record of over 91 billion cubic feet per day (Bcfpd), with 87% from domestic consumption and the remainder from LNG exports. Currently, natural gas consumption consists of approximately 42% (33 Bcfpd) for electric power, 25% (20 Bcfpd) for industrial use, 13% (10 Bcfpd) for residential use, 10% (8 Bcfpd) for commercial use, and 8% (about 10 Bcfpd) for other sources, including consumption from transportation, pipeline and distribution operations, and citygate use. The EIA forecasts consumption to grow in all sectors this year except for electric power, which had been the source of most natural gas consumption growth in the previous decade. While we project future growth, we believe this year's relative pause in electric power demand signifies the calm before the storm, given the expected surge in utility-scale generation driven by the rapid expansion of data centers.

In 2023, the United States consumed 32.5 Tcf of natural gas, representing nearly 36% of total primary energy consumption, with the most frequent usage consisting of electricity generation and heating. The electric power sector consumed 12.9 Tcf, accounting for over 40% of total U.S. energy consumption. The industrial sector used 10.5 Tcf (32%), relying on natural gas for both power generation and as a critical feedstock for producing chemicals, fertilizers, and other goods. Residential consumption totaled 4.5 Tcf (14%), with about 60% of U.S. homes depending on natural gas. The commercial sector consumed 3.3 Tcf (10%), largely for heating and electricity in buildings, often through combined heat and power systems, while transportation represented 1.3 Tcf (4%), mainly for pipeline compressors. The total consumption by region had Texas leading with 16% utilization, followed by California (6%), Louisiana (6%), Pennsylvania (6%), and Florida (5%), which combined equate to nearly 40% of the nation's total natural gas consumption.

Exhibit 29
Pain at the Plug
Annual U.S. Natural Gas Consumption by Sector (2000-2025)



Sources: U.S. Energy Information Administration (August 2025) and William Blair Equity Research

Utility-Scale-Generation Math

If U.S. utility-scale generation is 4,200 terawatt-hours per year (TWh/year) today, a 2% CAGR adds 920 TWh over 10 years. At a 43% gas share, which could rise in the coming years, this translates to 396 TWh/year of new gas-fired generation, requiring 7.3 Bcfpd of additional average gas burn by year 10.

Useful conversion rules of thumb (assuming a modern Combined Cycle Gas Turbine [CCGT] heat rate of about 7 MMBtu/MWh):

- 1 TWh/yr → ~6.75 Bcf/yr → ~0.0185 Bcfpd
- 100 TWh/yr → ~1.85 Bcfpd
- 1 GW CCGT @ 60% CF → ~0.10 Bcfpd

System operators and local distribution companies generally require firm transport capacity to exceed the average daily burn by 15%-30% to ensure reliability, cover maintenance, and accommodate peak demand days. Based on projected demand growth, planning for approximately 8.5-9.5 Bcfpd of new firm transportation by year 10 is prudent, emphasizing the need for diverse supply sourcing.

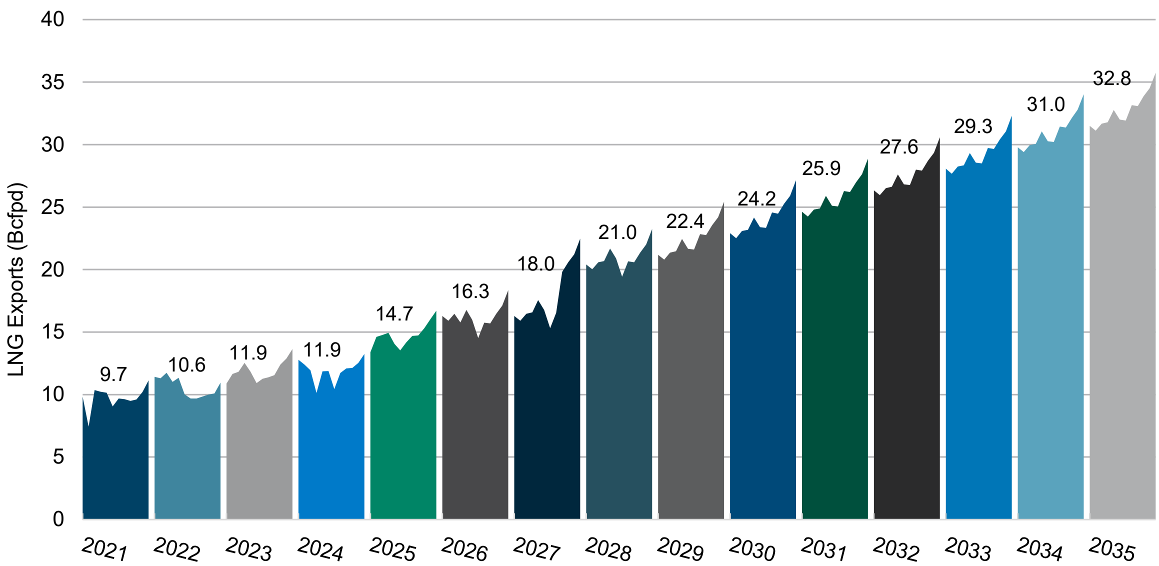
Time-staged markers (same assumptions):

- Year 5: +3.5 Bcfpd avg (→ ~4.3 Bcfpd firm)
- Year 10: +7.3 Bcfpd avg (→ ~9.0 Bcfpd firm)
- Year 15: +11.5 Bcfpd avg (→ ~14.2 Bcfpd firm)

LNG a Powerful Follow-up of Natural Gas Demand One-Two Punch

U.S. natural gas demand is set to rise significantly over the coming decade. Domestic consumption is estimated to rise by nearly 10 Bcfpd, while LNG demand is projected by the EIA and various energy producers to more than double to roughly 25 Bcfpd in the next 10 years, adding pressure to natural gas prices. The U.S. became the world's largest LNG exporter two years ago when exports reached 12 Bcfpd. We expect strong accelerating growth trend as new facilities, such as Plaquemines and Golden Pass, come online in the coming months, followed by Port Arthur and Rio Grande in the following quarters. LNG exports remain the largest source of demand growth, with EIA forecasts calling for a 36% increase (4.3 Bcfpd) in LNG exports from 2024 to 2026, outpacing the 1.0 Bcfpd of domestic consumption growth expected. By 2026, the average U.S. domestic consumption is projected at 91.4 Bcfpd, with the electric power sector remaining the largest consumer at roughly 40% of domestic natural gas consumption.

Exhibit 30
Pain at the Plug
U.S. Historical and Estimated Average LNG Exports (Bcfpd)



Source: William Blair estimates

Exhibit 31, on the following page, highlights key U.S. LNG projects undergoing construction or operating commercially, with a mix of brownfield expansions and new greenfield pipelines, representing significant capacity growth opportunities through 2029 and onward. These new expansions and pipelines will add over 7 Bcfpd to U.S. export capacity by 2029. Large-scale facilities already online include Sabine Pass, Cameron, Elba Island, and Calcasieu Pass, and they account for nearly 8.5 Bcfpd of current operating capacity. Near-term growth is led by Corpus Christi Stage 3, alongside Plaquemines LNG Phase 1 and Phase 2. Combined, these three facilities will lift U.S. LNG capacity by about 6.0 Bcfpd, or 53% above year-end 2024 levels, well ahead of prior EIA estimates. Longer-dated projects, such as Port Arthur LNG Phase 1 and Woodside Louisiana LNG Phase 1, will further expand capacity, reinforcing the Gulf Coast as the dominant hub for global LNG exports and cementing the U.S. position as the world's largest LNG supplier.

Exhibit 31
Pain at the Plug
U.S. Large-Scale LNG Projects

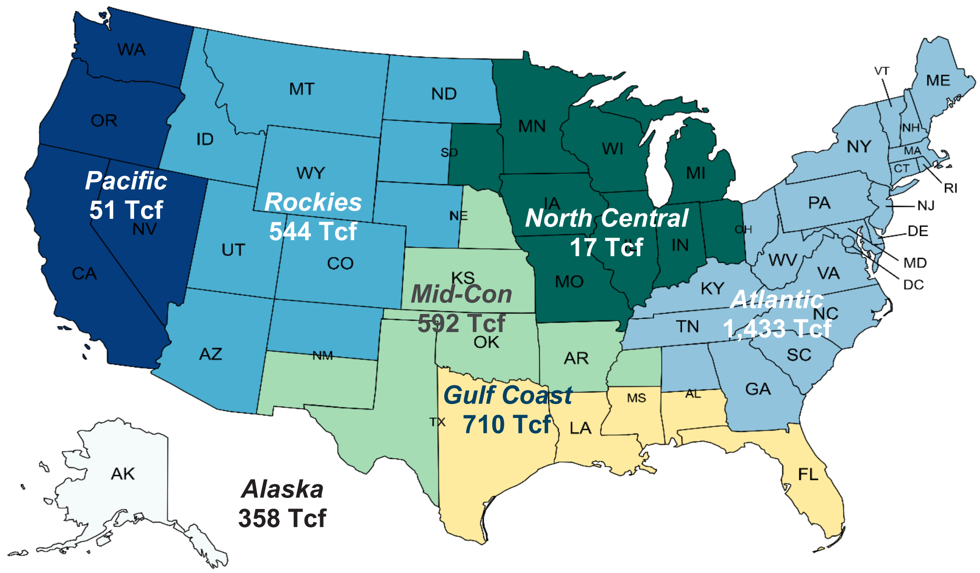
Project	Type	State	Peak Capacity (Bcfpd)	Project Status	Estimate In-Service Date	Operator
Sabine Pass, Train 1-6	Brownfield	LA	4.56	Commercial operation	Dec-21	Cheniere Energy
Cove Point, Train 1	Brownfield	MD	0.76	Commercial operation	Mar-18	Berkshire Hathaway BHE GT&S
Elba Island, Trains 1-10	Brownfield	GA	0.36	Commercial operation	May-20	Kinder Morgan
Corpus Christi, Train 1-3	Greenfield	TX	2.40	Commercial operation	Dec-20	Cheniere Energy
Cameron, Trains 1-3	Brownfield	LA	1.98	Commercial operation	Aug-20	Sempra LNG
Freeport, Train 1-3	Brownfield	TX	2.37	Commercial operation	Jul-19	Freeport LNG Development
Calcasieu Pass, Trains 1-18	Greenfield	LA	1.58	Commercial operation	Mar-22	Venture Global LNG
Plaquemines LNG Phase 1, Trains 1-18	Greenfield	LA	3.16	Commissioning	Sep-25	Venture Global LNG
Corpus Christi Liquefaction Stage 3, Trains 1-7	Brownfield	TX	1.51	Commissioning	Feb-25	Corpus Christi Liquefaction Stage III
Golden Pass, Train 1-3	Brownfield	TX	2.40	Under construction	2026/2027	Qatar Petroleum, ExxonMobil
Port Arthur LNG Phase 1, Trains 1-2	Greenfield	TX	1.78	Under construction	2027	Sempra Energy
Rio Grande LNG Phase 1, Train 1-3	Greenfield	TX	2.31	Under construction	2027/2028	NextDecade Corporation
Woodside Louisiana LNG Phase 1, Trains 1-3	Greenfield	LA	2.18	Under construction	2029	Woodside Energy
U.S. Total LNG Export Projects			**27.34**	**Bcfpd**		

Sources: U.S. Energy Information Administration (March 2025) and William Blair Equity Research

Ample Domestic Supply

While we forecast future natural gas demand to be materially stronger than the EIA and other agencies suggest, there is also a substantial amount of total future gas reserves and resources that we believe should provide ample near-term term supply and help stabilize natural gas prices in the long run. Currently, there are about 3,705 Tcf in total recoverable resources, representing a nearly 25% increase from the start of 2021, which had 2,973 Tcf of recoverable resources as reported by the EIA. As a rule, U.S. shale reservoirs account for roughly 58% of total natural gas resources, or about 2,147 Tcf of technically recoverable supply as of 2024. The remainder is distributed across conventional reservoirs, tight gas formations, coalbed methane, and proved natural gas reserves reported at year-end.

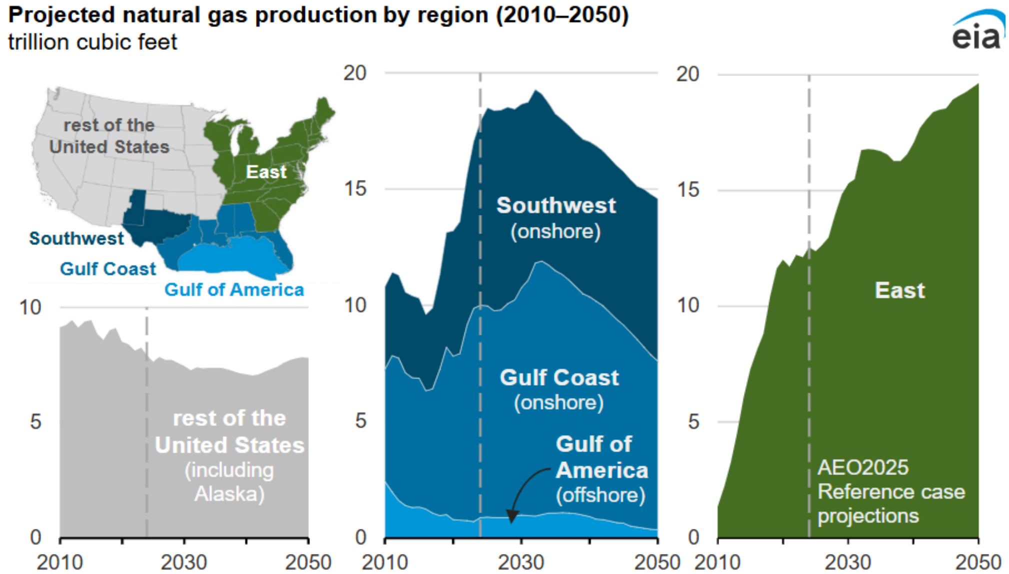
Exhibit 32
Pain at the Plug
Traditional Natural Gas Resources (Tcf)



Sources: U.S. Energy Information Administration (2024) and William Blair Equity Research

The Atlantic region holds the largest quantity of traditional gas resources in the U.S., driven by steady shale growth since the mid- to late 2000s, followed by the Mid-Continent and Rocky Mountain regions. This growth over the last 20 years has been fueled by technological innovations, such as horizontal well drilling and multistage hydraulic fracturing techniques. The EIA projects that the Atlantic, particularly the Appalachian Basin, will account for much of the future U.S. natural gas production growth, with output projected to rise nearly 7 Tcf over the next 25 years, to as high as 20 Tcf by 2050, given the region's abundant and economical-to-access U.S. resources. The Southwest, which includes the Permian and Mid-Continent plays, along with the Gulf Coast's Haynesville and Eagle Ford plays, is expected to see notable growth in the next 5 to 10 years before beginning to decline. The rest of the U.S., including Alaska, is suggested to decline over time but will gradually stabilize by 2030.

Exhibit 33
Pain at the Plug
Projected Natural Gas Production by Region (2010-2050)



Source: U.S. Energy Information Administration (April 2023)

William Blair estimates suggest that U.S. production could grow by as much as 10.5 Bcfpd, or 10%, to 117 Bcfpd from 2025 to 2030 if natural gas prices are as high as $4.50/Mcf and assuming "normal" capital discipline. Our analysis considers inventory in all the major domestic regions along with associated gas (assuming "normal" oil production), while factoring in domestic consumption and LNG exports previously noted. We estimate that at less than $2.50/Mcf natural gas prices and slightly wider well spacing assumptions, the two largest natural gas plays have only about four years of economic inventory left. However, we also calculate Appalachia and Haynesville could have as much as 67 years of economic inventory left at less than $4.50/Mcf natural gas prices and slightly tighter well spacing assumptions.

Exhibit 34
Pain at the Plug
U.S. Dry Gas Production Sensitivity Analysis

	U.S. Dry Gas Production Sensitivities				
$/Mcf	$2.50	$3.00	$3.50	$4.00	$4.50
Production by 2030 (Bcfpd)	105	107	114	116	117
Nominal Growth (vs '25, Bcfpd)	-2.0	0.5	7.6	9.0	10.5
% Growth (vs '25)	-2%	0%	7%	8%	10%

Sources: Company reports and William Blair Equity Research

Exhibit 35
Pain at the Plug
Well Spacing vs. Gas Price Breakeven – Appalachia

Appalachia - Remaining Locations

Gas Price Breakeven	Well Spacing 1056'	Well Spacing 880'	Well Spacing 660'
<$2.50	1237	1237	1823
<$3.00	6255	8251	11238
<$3.50	9815	12228	16566
<$4.00	11105	13883	18424
<$4.50	11581	14460	19760

Appalachia - Remaining Years of Inventory

Gas Price Breakeven	Well Spacing 1056'	Well Spacing 880'	Well Spacing 660'
<$2.50	2.3	2.3	3.4
<$3.00	11.6	15.3	20.8
<$3.50	18.2	22.6	30.7
<$4.00	20.6	25.7	34.1
<$4.50	21.4	26.8	36.6

Sources: Enverus and William Blair Equity Research

Exhibit 36
Pain at the Plug
Well Spacing vs. Gas Price Breakeven – Haynesville

Haynesville - Remaining Locations

Gas Price Breakeven	Well Spacing 1056'	Well Spacing 880'	Well Spacing 660'
<$2.50	675	962	1175
<$3.00	4358	5072	7359
<$3.50	6287	7857	11652
<$4.00	6720	8451	12252
<$4.50	6766	8546	12345

Haynesville - Remaining Years of Inventory

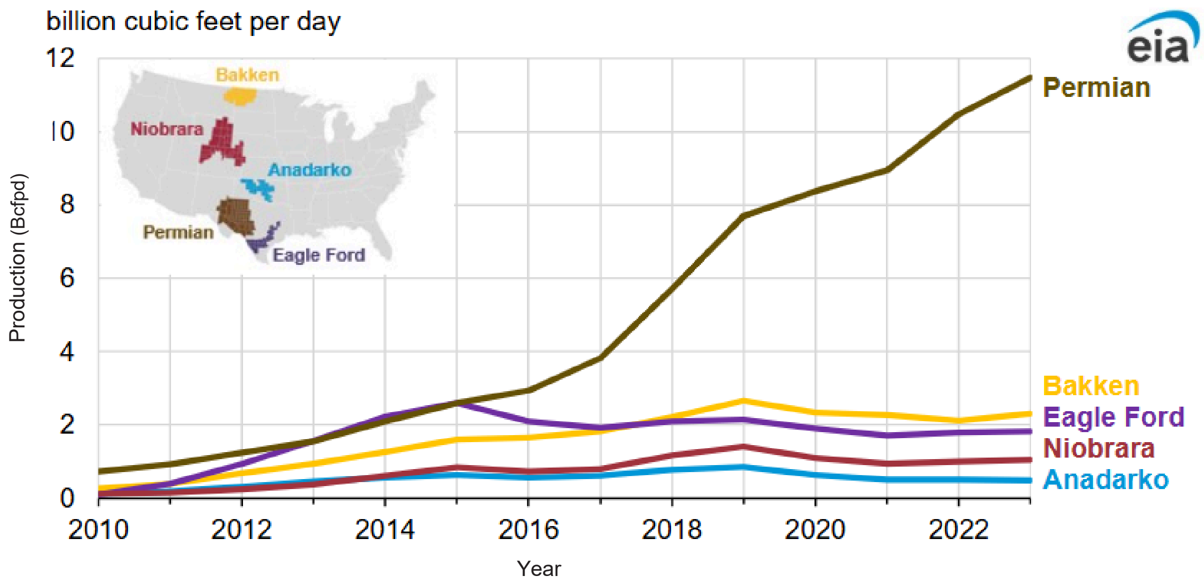
Gas Price Breakeven	Well Spacing 1056'	Well Spacing 880'	Well Spacing 660'
<$2.50	1.7	2.4	2.9
<$3.00	10.8	12.5	18.2
<$3.50	15.5	19.4	28.8
<$4.00	16.6	20.9	30.3
<$4.50	16.7	21.1	30.5

Sources: Enverus and William Blair Equity Research

Associated Gas

Out of total U.S. natural gas production levels in 2023, 36.7% of the total output was associated natural gas, a marginal decline from 37.4% in 2022. Associated natural gas production, which is natural gas produced by wells that predominantly produce oil, comes mainly from five major oil-producing regions in the U.S.: the Permian, Bakken, Eagle Ford, Anadarko, and Niobrara. Associated gas contains natural gas plant liquids including butane, ethane, and propane, and on occasion is referred to as "wet gas," because it requires additional processing treatment to remove impurities before the marketing process. The overall increase in associated gas has led to increased ethane production, used in the production of fibers, plastics, and other marketable products. The exponential rise in associated natural gas production in the Permian Basin is depicted in exhibit 37, followed by the Bakken and Eagle Ford.

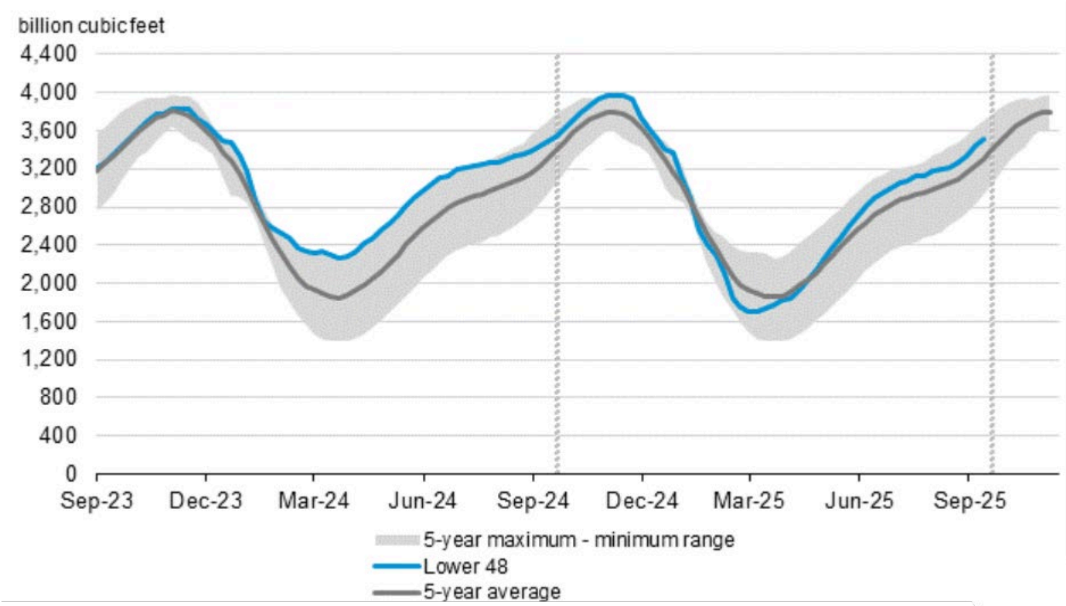
Exhibit 37
Pain at the Plug
Annual U.S. Associated Natural Gas Production by Basin (Bcfpd)



Sources: U.S Energy Information Administration (November 2024) and Enverus

Natural gas supply and demand will continue to be impacted by U.S. underground natural gas storage, with demonstrated peak capacity of 4.277 Tcf (total U.S. underground natural gas storage maximum capacity is about 9.363 Tcf), and more importantly by pipeline availability. The continued relatively low peak capacity restricts how much gas can be injected into storage during warmer months and, more critically, limits the amount that can be withdrawn during winter, creating the risk of supply shortages during abnormally cold periods. Further, the limited peak storage confines how much natural-gas-fired power plants can ramp up to meet spikes in electricity demand, leaving the entire system more susceptible to grid instability.

Exhibit 38
Pain at the Plug
U.S. Working Natural Gas in Underground Storage (Bcf)



Source: U.S. Energy Information Administration (September 2025)

Midstream Constraints

The largest bottleneck of U.S. natural gas supply continues to be not upstream, but midstream, as pipeline takeaway capacity is limited for natural gas production in several key U.S. regions. As of late, the limited takeaway continues to pose a particular problem in the Permian Basin, which accounted for 22% of U.S. marketed natural gas production in 2024. The supply constraint, or the inability to move gas out of the basin, is evident by the current -$1.65/Mcf price of Waha natural gas, the prominent hub in the region.

Midstream companies continue to build out natural gas infrastructure, adding 6.5 Bcfpd of Appalachia, Haynesville, Permian, and Eagle Ford pipelines. The existing and new pipes will deliver gas from producing regions to demand centers in the mid-Atlantic and Gulf Coast. Additional natural gas pipeline capacity is set to come online by 2027, with the Blackcomb Pipeline (+2.5 Bcfpd), Kinder Morgan's Gulf Coast Express expansion (+0.6 Bcfpd), and Energy Transfer's Hugh Brinson Pipeline (+1.5 Bcfpd) expected to be in service over the next few years. Several other major greenfield Permian projects reached a final investment decision this year and are scheduled to begin service later this decade, including Energy Transfer's Desert Southwest (+1.5 Bcfpd) and WhiteWater's Eiger Express (+2.5 Bcfpd), along with other recently proposed gas pipelines, such as Tallgrass Energy's Permian-to-Rockies Express connector.

Together, these projects represent about 4.5 Bcfpd of new takeaway capacity into demand centers, reflecting about half of the 10-year need. The remainder is expected to come from an integrated program of brownfield debottlenecking and select new pipe in the Permian-to-Desert Southwest/California and Marcellus-to-PJM/NY/NE corridors.

We anticipate further pipeline capacity added through a combination of brownfield enhancements and greenfield projects. Brownfield expansions typically provide the most cost-efficient means to increase throughput, often boosting existing pipeline capacity by 10%-25% through measures such as upgrading compressor stations, limiting looping, and optimizing the maximum allowable operating pressures. These strategic brownfield measures leverage existing rights and infrastructure, minimizing capital intensity and delays associated with acquiring the necessary permits. A clear example is the Mountain Valley Pipeline (MVP) Boost project, which came online in June 2024 and subsequently delivered a 25% uplift in throughout. We expect brownfield initiatives to account for roughly 40%-50% of the firm capacity required over the first six years of projected demand growth.

On the other hand, greenfield projects involve full-scale new pipeline construction, carrying a higher cost of about \$3 billion-\$4 billion per 1 Bcfpd of capacity, as proved by Energy Transfer's 1.5 Bcfpd project, which had a cost of about \$5.3 billion. Compression and looping debottleneck, while smaller in scale, typically deliver meaningful incremental capacity at a fraction of the cost to develop a greenfield pipeline, often requiring less than \$1 billion per 1 Bcfpd equivalent, varying by project.

A 10-year program: If 9.0 Bcfpd firm is needed and 60% comes from greenfield and 40% from brownfield:

- Greenfield ≈ 5.0-5.5 Bcfpd → \$17 billion-\$22 billion
- Brownfield ≈ 4.0-4.5 Bcfpd → \$3 billion-\$7 billion
- All in: \$20 billion-\$30 billion over a decade (feasible against scale of existing system and preceding projects)

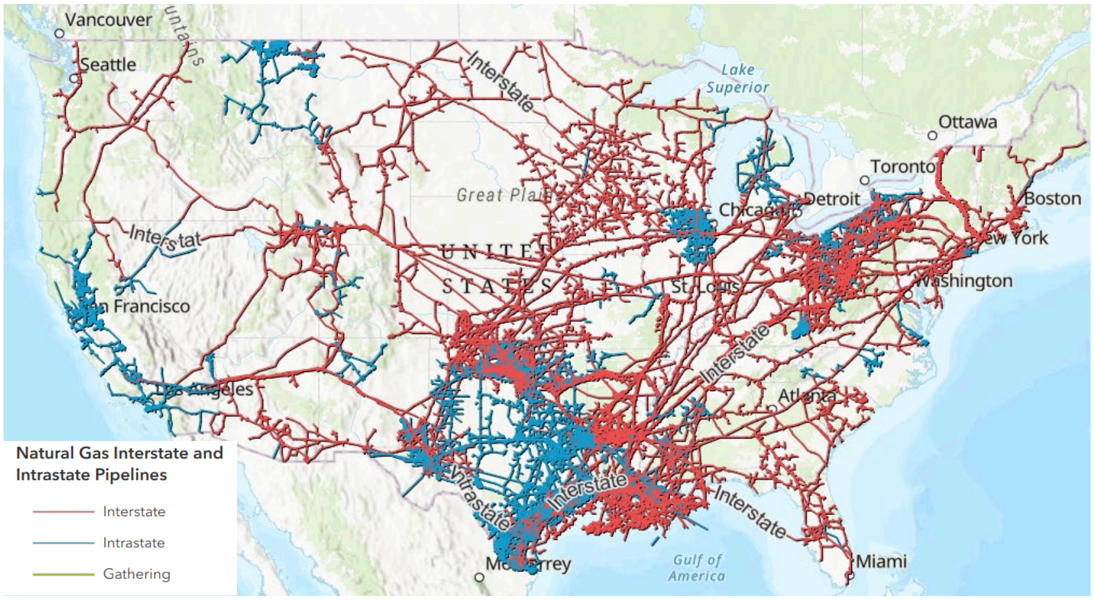
Exhibit 39
Pain at the Plug
U.S. Natural Gas Pipeline Projects – Proposed and Approved

Date	Project Name	Pipeline Operator	Type	Status	In-Service Date	State(s)	Additional Capacity (MMcf/d)
5/7/2024	Apex	Targa Resources	New Pipeline	Approved	2026	TX	2000
7/1/2025	Aspire Energy Express	Aspire Energy Express LLC	New Pipeline	Proposed	2027	OH	300
10/21/2024	Bison Xpress Project	Northern Border Pipeline Co.	Expansion	Approved	2026	ND,WY	300
7/15/2025	Driftwood Line 200 and 300 Project Phase 2	Driftwood LNG Pipeline	New Pipeline	Approved	2027	LA	4600
5/12/2023	Driftwood Line 200 and 300 Project Phase 3	Driftwood LNG Pipeline	New Pipeline	Approved	2028	LA	1000
5/12/2023	Driftwood LNG Pipeline	Driftwood LNG Pipeline	New Pipeline	Approved	2028	LA	4000
7/1/2025	Gillis Access Project Extension	TC Energy	Expansion	Approved	2027	LA	1400
1/30/2024	Hillabee Expansion Phase 3	Transcontinental Gas Pipe Line Company	Expansion	Proposed	2027	AL	106
10/21/2024	Holbrook Expansion Project	Cameron Interstate Pipeline	Expansion	Approved	2027	LA	1079
7/1/2025	Iroquois Expansion by Compression Project	Iroquois Pipeline Co	Expansion	Approved	2027	QU,NY,CT	125
7/1/2025	Louisiana Connector Amendment Project	Port Arthur Pipeline LLC	Expansion	Approved	2027	LA	70
8/15/2023	Louisiana Connector- Port Arthur Pipeline	Port Arthur Pipeline LLC	New Pipeline	Approved	2027	LA,TX	2000
1/8/2025	Marysville Connector Pipeline	Columbia Gas of Ohio	Expansion	Approved	NA	OH	NA
11/25/2024	Maysville Expansion Project	TC Energy	Expansion	Approved	2029	KY	200
11/25/2024	Pulaski Expansion Project	TC Energy Corp.	Expansion	Approved	2029	KY	200
6/25/2025	Rover-Bulger CS and Harmon Creek MS Expansion	Rover Pipeline	Expansion	Approved	2026	PA	400
3/8/2025	Sabal Trail Project Phase III	Spectra Energy Corp/NextEra Energy/Duke Energy	Expansion	Approved	2027	AL,GA,FL	76
8/15/2023	Texas Connector-Port Arthur Pipeline	Port Arthur Pipeline LLC	New Pipeline	Approved	2028	TX	2000
11/25/2024	Texas-Louisiana Expansion Project	Natural Gas Pipeline Company of America	Expansion	Approved	2026	TX,LA	467
4/8/2025	Traverse Pipeline	Whitewater Midstream	New Pipeline	Approved	2027	TX	1750
1/15/2025	Trident Pipeline	Kinder Morgan	New Pipeline	Approved	2027	TX	1500
7/23/2025	Wild Trail Project	Northwest Pipeline	Expansion	Proposed	2027	UT	83

Sources: U.S. Energy Information Administration (July 2025) and William Blair Equity Research

Exhibit 40, on the following page, depicts 22 U.S. natural gas pipeline projects primarily spanning the southern region, with 19 approved and 3 proposed pipelines, consisting of 9 greenfield pipelines and 13 brownfield expansions. Much of the new capacity is concentrated in Louisiana and Texas, driven by large LNG export-related projects such as Driftwood (over 9,000 MMcfd combined across phases), the Louisiana Connector-Port Arthur line (2,000 MMcfd), the Texas Connector-Port Arthur line (2,000 MMcfd), and Apex (2,000 MMcfd). Most of this capacity is projected to come online from 2026 to 2028, with smaller projects in states such as Ohio and Utah adding lower levels of additional capacity. Overall, these expansionary measures to the U.S. pipelines highlight the growing demand in the Gulf Coast, driven by LNG exports, with approved projects paving the way for increased domestic natural gas capacity.

Exhibit 40
Pain at the Plug
Natural Gas Interstate and Intrastate Pipelines



Source: U.S. Energy Information Administration (July 2025)

Pillar IV – Finance Architecture

To accelerate deployment of dependable power infrastructure, we believe it's crucial to reduce the friction of capital flowing toward reliable energy sources, such as nuclear, natural gas, and storage, rather than prioritizing narrow carbon accounting metrics that may overlook systemwide resilience and long-term sustainability.

In this section, we aim to reconnect financial mechanisms with energy fundamentals. Establishing an energy return floor ensures that public investment contributes to expanding the nation's surplus of useful work, lowering the cost of capital, and enhancing global competitiveness. A reliability credit compensates only when energy is most valuable, aligning incentives with grid stability. Stability bonds help maintain investment momentum through economic cycles, while a reserve account transforms volatile resource revenues into a consistent financial buffer. This approach helps ease the structural tension of being a global reserve currency, known as the Triffin dilemma. Together, these tools would reduce the friction that currently prevents capital from flowing to the most dependable sources of energy. They also would position the U.S. to lead in a world where capital is increasingly organized around tangible assets, energy security underpins monetary strength, and credibility belongs to nations that can keep the lights on and factories running during the most challenging times, not just when the sun is shining.

- ***Stop debt for sub-7 EROI assets:*** Federal credit, tax, or rate support only for portfolios with EROI-weighted average ≥7:1.

- ***Replace Investment Tax Credit (ITC)/Production Tax Credit (PTC) with Production Reliability Credit (PRC):*** A PRC paid per firm MWh delivered under stress hours (not nameplate).

- ***Baseload bonds:*** Designate regulated baseload and transmission as high-quality liquid assets eligible; allow regulated utilities to issue energy stability bonds with Fed repos in stress, limiting pro-cyclical capex cuts.

- ***Energy reserve account:*** Earmark federal royalties/LNG port fees into a stabilization fund that backstops PRC outlays—reducing external-deficit pressure implied by holding a reserve currency. Also use proceeds from mineral development to fund this account.

Stop Debt for Sub-7 EROI Assets
Public support should be directed only toward energy systems that deliver a strong surplus of usable energy over their full lifecycle. EROI is the most straightforward metric for evaluating that surplus. Setting an eligibility threshold at a minimum EROI of 7:1 ensures that federal backing supports technologies that demonstrably expand the real energy base of the economy. Nuclear, hydro, geothermal, and natural gas with secure fuel and storage meet this standard. Intermittent resources like wind and solar can qualify when paired with firming assets, storage, and grid services that raise the overall portfolio to meet the threshold.

This approach ties fiscal discipline to physical reality, in our view. Low-EROI systems require ongoing subsidies and frequent refinancing because they fail to generate enough net energy to sustain their own complexity, which drives the economy toward higher debt levels, an especially problematic trend as the U.S. shifts to a more national economic footing. In this context, the country exports currency, imports energy-intensive goods, and must service debt with declining EROI systems, which is an embodiment of the Triffin dilemma. Conditioning federal credit guarantees, tax incentives, and regulated rate treatment on an energy return floor introduces a vital risk control. It channels scarce capital toward assets that grow real output, strengthens the tax base, and reduces vulnerability to energy import shocks.

Implementation can be both rigorous and equitable. Program sponsors would certify portfolio-level EROI using transparent boundaries, from resource extraction to delivery at the meter, with penalties for storage losses and reliance on foreign inputs subject to disruption. Independent engineers and institutions would audit these calculations using established lifecycle analysis standards. The goal is not to legislate winners, but to ensure that public support amplifies national energy surplus rather than depleting it. In a world where foreign buyers are less willing to absorb new Treasury issuance, that insistence becomes a cornerstone of monetary resilience.

Replace ITC/PTC With PRC
Current investment and production credits often reward installed capacity or average energy output, but these metrics do not guarantee performance when the grid is under stress. They can inflate financial returns without delivering the dependable power the economy needs during its most critical hours. A production reliability credit reverses this incentive structure by paying only for verified firm output delivered during defined stress periods, such as peak net load hours, scarcity pricing intervals, cold snaps, and heat waves. The credit is technology-neutral, which means any plant or storage system that delivers certified firm megawatt-hours during these windows qualifies. Renewable assets can participate by adding storage, firming contracts, and meeting telemetry and dispatch standards that prove performance when it matters most.

This simple shift aligns private investment decisions with system reliability needs. Developers will prioritize fuel assurance, maintenance discipline, and deliverability because that is what earns the payout. Market distortions such as negative pricing diminish, and reliance on emergency out-of-market contracts declines. Over time, the grid builds a portfolio capable of withstanding weather shocks and supply disruptions, which helps stabilize prices and supports energy-intensive industries. This, in turn, contributes to more predictable inflation and interest rates, easing pressure on the broader fiscal landscape. In this way, a reliability credit is not just an energy policy; it is a monetary stabilizer, growing the stock of assets that deliver real value on demand rather than fragile financial claims.

Implementation seems straightforward and transparent. Regional grid operators would publish the calendar and criteria for stress windows in advance. Verified delivery would rely on high-resolution metering and standardized telemetry. Payments would be settled monthly, with clawbacks for nonperformance. The credit rate could be indexed to a reliability metric, such as expected unserved energy, rising when the system is tight and falling when reserve margins improve. The result would be a self-correcting incentive that rewards what truly keeps households powered and factories running.

Baseload Bonds

Critical utility investment often falls at the very moment it is most needed. When financial markets tighten, spreads widen, equities falter, and utilities often cut capital spending to protect their balance sheets. This delays new capacity and grid upgrades, imposing pro-cyclical austerity on critical infrastructure. Reclassifying regulated utility assets as high-quality liquid holdings for banks and making properly structured utility bonds eligible for central bank repurchase operations during periods of stress would shift this dynamic. It would transform the debt of tightly regulated cost-of-service assets into a domestic safe asset that remains fundable throughout the economic cycle.

Energy stability bonds would be issued with strict safeguards. Proceeds would be restricted to rate-regulated baseload generation and transmission projects that meet a defined energy return standard and have approved cost recovery mechanisms. Bond covenants would require transparent capital plans, fuel assurance where applicable, independent engineering reviews, and ongoing performance reporting to state commissions and federal energy regulators. Central bank haircuts would be calibrated to asset type and fuel risk. This structure does not socialize business risk, in our opinion; it acknowledges that reliable power is a public necessity and that a modern economy cannot afford stop-start investment in its foundational infrastructure.

The benefits extend well beyond the utility sector. As foreign demand for U.S. Treasurys declines and global savings shift toward domestic priorities in aging economies, the U.S. will need new classes of credible, liquid, and productivity-enhancing assets. Properly ring-fenced utility bonds can help fill that role, in our view. They reduce the cost of capital for reliability-focused projects, sustain construction during downturns, and provide banks with liquidity buffers tied to real, productive assets. A power system that continues to invest through recessions becomes a stabilizing force for industry and a foundation for monetary credibility.

Energy Reserve Account

A nation that issues the world's leading reserve currency faces a persistent structural challenge, which is that global demand for dollar liquidity often drives domestic deficits. This is the essence of the Triffin dilemma. The solution is not simply expanding central bank balance sheets. We believe a more resilient approach is to recycle domestic resource revenues into a countercyclical stabilizer that supports grid reliability during periods of stress, without adding to fiscal pressure. An energy reserve account would serve this purpose. When commodity prices are high and export volumes strong, federal royalties and port fees would accumulate in the account. During reliability crises or frequent stress windows, the account would fund production reliability credits and, if necessary, emergency procurement of fuel and critical components. These flows are intentionally countercyclical.

Governance would be rules-based and transparent. Deposits would be automatic, drawn from clearly defined revenue streams. Withdrawals would be triggered by objective metrics, such as moving averages of stress hours, reserve margin thresholds, or emergency declarations by regional grid operators. The account would prioritize liquid, low-risk instruments and could include a modest allocation to neutral tangible reserves like gold to hedge against sanction and currency risks that cannot be diversified away. The goal is not speculation, but rather to ensure that the U.S. maintains a domestic buffer that supports reliability without resorting to emergency borrowing at the worst possible time.

The account could also fund long-lead, high-return energy projects such as strategic transmission corridors, fuel storage infrastructure, and permitting modernization for energy-dense resources. States could establish matching funds to ensure local royalties and fees align with regional grid needs while still contributing to the national backstop. By linking fiscal flows to energy performance, the Energy Reserve Account strengthens the monetary system rather than weakening it. It would ensure supply remains available, reliability stays high, and the dollar retains credibility, backed by an economy capable of delivering real goods and services even under strain.

Pillar V – The Quest for $25 MW/Hr Delivered Power: Fund R&D Related to Energy Moonshots

Investing in research is critical to unlocking the full potential of advanced energy generation technologies. Breakthroughs in areas such as nuclear fusion, thorium-based fission reactors, and geothermal depend on sustained and strategic funding. Research not only drives innovation, but also reduces technical risk, shortens development timelines, and lowers costs, which can make emerging technologies more viable for commercial deployment. By prioritizing public and private investment in energy R&D, governments can catalyze a new era of clean, resilient, and scalable energy systems that support climate goals, economic growth, and national security.

Fusion

Fusion generation is the process of fusing atomic nuclei to release vast amounts of energy, and it represents one of the most promising frontiers in clean power generation. Deuterium and tritium are the main fuel sources. While deuterium is widely available, tritium requires breeding, part of the technological development of a fusion program. Unlike fission, fusion produces no long-lived radioactive waste and carries minimal risk of meltdown, making it inherently safer and more sustainable. Fusion produces significantly more energy than fission by converting a greater portion of atomic mass into energy. To initiate fusion, atomic nuclei must be heated to extremely high temperatures, forming a plasma, which is an ultra-hot, electrically charged gas. This plasma can be manipulated using magnetic fields, which are generated by electric currents flowing through the plasma itself. These magnetic fields help confine and steer the plasma, keeping it away from reactor walls and maintaining the extreme conditions necessary for fusion. However, magnetic confinement is not perfect; plasma tends to leak over time, which poses a challenge to sustaining continuous fusion reactions.

Magnetic confinement fusion has traditionally centered on the tokamak, a toroidal (i.e., donut-shaped) device engineered to heat and contain plasma using magnetic fields. It relies on two key magnetic components, which are the poloidal field, generated by the plasma itself, and the toroidal field, produced by external coils. Together, these fields form a magnetic cage that stabilizes the plasma and prevents it from drifting or cooling, thereby increasing the chances of sustained fusion reactions. Scaling up tokamaks has proved beneficial, as larger devices retain heat more effectively due to a favorable surface-area-to-volume ratio, which enhances energy confinement time. This principle drove major breakthroughs from the 1970s to the 1990s, with machines like the Joint European Torus (JET), the Tokamak Fusion Test Reactor (TFTR) in the U.S., and Japan's JT-60 achieving extended plasma durations and generating MW of fusion power. Notably, JET reached 16 MW of fusion output in 1997 with a Q-ratio, which represents the ratio of fusion output versus input power, of 0.67. Building on these scaling laws, the International Thermonuclear Experimental Reactor (ITER) project is now being built to reach a Q-ratio of 10, which underscores that fusion can produce significantly more energy than it consumes. This milestone would mark a critical step toward commercial fusion power. With continued investment and innovation, fusion holds the promise of delivering a significantly more energy dense system than nuclear fission, thereby driving down cost toward $25MW/hr.

On the international front, fusion energy development is expanding rapidly. The ITER project is the world's largest and most sophisticated fusion experiment, which is based in France. However, like Vogtle, which we view as a convenient stalking horse against nuclear fission, we believe the ITER project represents the same for fusion. Why? Like most multinational bureaucratic experiments (space programs), we cannot think of one that has come in on time or under budget. Similarly, while we are certain there have been meaningful discoveries and innovations from the ITER project, we also believe the private sector may be where fusion is first commercialized.

ITER brings together contributions from China, the European Union, India, Japan, South Korea, Russia, and the U.S., with additional support from countries like Australia and Canada. ITER's goal is to prove that fusion can be scaled for commercial use, aiming to produce 500 MW of power with a tenfold energy return. Although full-scale operations have been delayed until 2039, ITER continues to serve as a foundational effort in fusion research. Meanwhile, individual nations are advancing their own fusion agendas. China leads with an annual fusion budget of $1.5 billion, and its Experimental Advanced Superconducting Tokamak reactor recently broke records by maintaining plasma for over 17 minutes. Japan is pushing forward with the Fusion by Advanced Superconducting Tokamak project and backing start-ups like Helical Fusion, which aim to deploy commercial reactors by the 2040s. South Korea is making strides with its Korea Superconducting Tokamak Advanced Research reactor, and Spain is developing the Small Aspect Ratio Tokamak reactor in partnership with U.S. institutions. The International Atomic Energy Agency (IAEA) has highlighted this momentum in its *World Fusion Outlook,* declaring fusion a near-term reality rather than a distant aspiration. To support this shift, the IAEA has established the World Fusion Energy Group, which promotes international cooperation, policy harmonization, and workforce development. The agency emphasizes the importance of enabling technologies, clear regulatory frameworks, and strong public–private partnerships to accelerate the path to commercialization.

The U.S. continues to fall behind China in the race to develop fusion power. While China is spending $1.5 billion annually, the DOE has committed to only $134 million, less than a tenth of China. We posit that private sector companies, backed by some of the world's largest companies and wealthiest individuals, are attempting to step in where the U.S. government has thus far failed. Considering the minimal investment in fusion compared with U.S. spending for solar and wind, variable assets that have ostensibly weakened our grids and national security, one might conclude the government has failed in this domain.

Advancements in magnetic confinement and laser ignition are bringing fusion closer to commercial viability, which is being propelled by a diverse group of innovative start-ups and ventures, each exploring unique technological pathways. Commonwealth Fusion Systems, an MIT spin-off, is advancing compact tokamak reactors with high-temperature superconducting magnets, aiming to demonstrate net energy gain with its SPARC reactor and launch a commercial ARC reactor in the early 2030s. Helion Energy, headquartered in Washington, is pursuing Magneto-Inertial Fusion and plans to supply fusion electricity to Microsoft by 2028 via its Polaris reactor. TAE Technologies, supported by Google and Chevron, is working on aneutronic fusion using hydrogen-boron fuel, with its Copernicus reactor expected to begin operations soon. Other key players like Zap Energy, General Fusion, and Tokamak Energy are also contributing novel reactor designs and attracting substantial investment. Collectively, these companies are accelerating the path toward commercial fusion energy.

Exhibit 41
Nuclear Industry
Leading Companies in the Nuclear Fusion Market

Company	Location	Funding Raised	Technological Approach	Strategic Partners
Commonwealth Fusion Systems	Cambridge, MA	$3.0B+	Pioneering a compact tokamak reactor design that leverages high-temperature superconducting magnets	Google, Dominion Energy, Eni
TAE Technologies	Foothill Ranch, CA	$1.3B+	Advancing a unique fusion method based on the Field-Reversed Configuration, which uses neutral beam injection to heat and stabilize plasma	Google, Chevron, Venrock, Princeton Plasma Physics Lab
Helion Energy	Everett, WA	$1.0B+	Developing a unique fusion system based on magneto-inertial confinement, which combines magnetic fields and plasma compression to achieve fusion conditions	Microsoft, Nucor
Pacific Fusion	Freemont, CA	$900M+	Advancing a pulsed magnetic fusion system that leverages fast, high-current electrical pulses to generate intense magnetic fields, compressing and heating fusion fuel to achieve ignition	Breakthrough Energy Ventures, General Catalyst, Temasek, Google
General Fusion	Richmond, BC, Canada	$477M+	Core innovation lies in its Magnetized Target Fusion technology, which combines aspects of magnetic and inertial confinement	Segra Capital, PenderFund, Chrysalix Venture Capital
Tokamak Energy	Oxfordshire, UK	$335M+	Advancing fusion energy through its compact spherical tokamak design, which enhances plasma stability, efficiency, and cost-effectiveness compared to conventional tokamaks	Furukawa Electric, British Patient Capital, BW Group, Sabanci Climate Ventures
Zap Energy	Seattle, WA	$330M+	Centered on the sheared-flow-stabilized Z-pinch method, a novel approach that eliminates the need for massive superconducting magnets or high-powered lasers	Breakthrough Energy Ventures, Chevron Technology Ventures, Shell Ventures
Marvel Fusion	Munich, Germany	$160M+	Utilizing a laser-driven inertial confinement fusion method, using ultrashort, high-intensity laser pulses to ignite fusion reactions in nanostructured fuel targets	Siemens Energy Ventures, EQT Ventures, European Innovation Council
Type One Energy	Madison, WI	$80M+	Pursuing a next-generation fusion system based on the stellarator design, which enables steady-state plasma confinement without the need for driven currents	Tennessee Valley Authority, AECOM

Sources: Company reports and William Blair Equity Research

Thorium-Based Fission Reactors

Thorium-based fission is an alternative nuclear energy pathway that uses thorium-232 as fuel, which is more abundant and widely distributed than uranium. When irradiated, thorium converts into uranium-233, a fissile material capable of sustaining a nuclear reaction. Thorium reactors offer several advantages: 1) produce significantly less long-lived radioactive waste, 2) lower risk of proliferation, and 3) operate with enhanced safety features. Despite its promise, thorium technology remains underdeveloped because of limited commercial experience and infrastructure. Continued research and funding could unlock its potential as a clean, scalable, and secure energy source that has the potential to diversify the nuclear fuel cycle, reduce waste management costs, and enhance global energy resilience.

Governments and research institutions worldwide are ramping up support for thorium-based fission reactor technologies as part of a broader effort to develop cleaner, safer, and more sustainable nuclear energy solutions. In the U.S., the DOE's Nuclear Reactor Pilot Program is backing 11 advanced reactor initiatives, some of which are exploring thorium fuel cycles, with the aim of deploying operational test reactors by 2026. A key example of public and private collaboration is the partnership between Clean Core Thorium Energy, Idaho National Laboratory (INL), and Texas A&M University, which is testing the ANEEL fuel, a blend of thorium and high-assay low enriched uranium, at INL's Advanced Test Reactor.

Globally, the IAEA has led multiyear research programs to evaluate thorium's potential, citing its abundance, reduced radioactive waste, and resistance to nuclear proliferation. Innovative reactor designs like molten salt reactors and accelerator-driven systems are being studied for their compatibility with thorium, offering promising safety and efficiency advantages. For example, China is spearheading the development of a thorium-based molten salt reactor in the Gobi Desert, marking a major leap in nuclear energy innovation. The initiative follows the successful operation of a 2 MW prototype reactor and aims to scale up to a 10 MW demonstration reactor by 2030. Despite hurdles such as high extraction costs and limited operational experience, the growing momentum from governments, national labs, and academic institutions reflects a strong commitment to realizing thorium's role in the future of nuclear energy.

In the private sector, investment and venture capital interest in thorium-based fission reactors is accelerating as the energy industry looks for innovative, low-risk alternatives to conventional nuclear power. Firms like Nucleation Capital are leading the charge and enabling investments to back start-ups such as Copenhagen Atomics, which is developing compact thorium molten salt reactors designed to safely process nuclear waste. These investment models offer early-stage equity access and reflect growing market confidence in thorium's commercial potential. Thorium Energy Ventures, supported by executives from major global corporations, is advancing the Tesseract reactor, a modular, thorium-optimized system focused on cost-effectiveness and energy resilience. Flibe Energy, founded by former NASA engineer Kirk Sorensen, is pushing forward with liquid-fluoride thorium reactor technology, targeting applications beyond electricity generation, including water purification and space propulsion. As research expands and venture funding continues to flow, private sector engagement is becoming a key driver in the development and deployment of thorium reactor technologies.

Exhibit 42
Nuclear Industry
Leading Companies in the Thorium Reactor Market

Company	Location	Funding Raised	Technological & Market Approach	Strategic Partners
Thorizon	Amsterdam, Netherlands	$45M+	Thorizon One features a modular cartridge fuel system that enhances safety, simplifies maintenance, and supports circular nuclear energy practices	Storabelle, Orano, VDL Groep, EDF
Transmutex	Geneva, Switzerland	$31M+	Transmutex's technology supports green hydrogen production and the extraction of valuable medical isotopes, positioning Transmutex at the intersection of clean energy, waste management, and nuclear medicine	Via, Steel Atlas, Union Square Ventures, Presight Capital, At One Ventures
Copenhagen Atomics	Copenhagen, Denmark	$20M+	Pioneering a compact, modular thorium molten salt reactor design, built into standard 40-foot shipping containers	Topsoe, Alfa Laval, Aalborg CSP, Pertamina, Pupuk Kaltim
Clean Core Thorium Energy	Chicago, IL	$18M+	Revolutionizing nuclear energy through its patented ANEEL fuel, a blend of thorium and HALEU, enabling a plug-and-play solution for existing pressurized heavy-water reactors	Larsen & Toubro, Idaho Strategic Resources
Flibe Energy	Huntsville, AL	$4M+	Developing Liquid Fluoride Thorium Reactors, a class of molten salt reactors that use thorium as fuel and operate with liquid fuel rather than solid assemblies	Savannah River National Laboratory
Thorium Energy Ventures	Toronto, ON, Canada	NA	Flagship design known as the Tesseract reactor uses Th-232 pellets as fuel and helium or CO_2 as coolant, operating at low pressure and designed for a 30- to 60-year lifespan	Idaho National Laboratory, Canadian Nuclear Laboratories, Larsen & Toubro

Sources: Company reports and William Blair Equity Research

Geothermal

Geothermal energy harnesses heat from beneath the Earth's surface to generate electricity and provide direct heating, offering a reliable and low-emission source of baseload power. Unlike solar and wind, geothermal is not weather-dependent and can operate continuously, making it a valuable complement to intermittent renewables. However, its widespread adoption has been limited by high upfront costs, geological uncertainties, and limited access to suitable sites. Continued research and funding can unlock advanced drilling techniques, expand enhanced geothermal systems, and improve resource mapping, which will dramatically increase the geographic reach and economic viability of geothermal projects. Strategic investment in this field could yield high returns by enabling scalable, clean energy that supports grid stability and decarbonization goals.

Support for geothermal energy is expanding significantly both in the U.S. and around the world, driven by its promise as a clean, dependable, and scalable energy source. In the U.S., the DOE's Geothermal Technologies Office is spearheading efforts to lower costs and accelerate deployment, notably through initiatives like the Enhanced Geothermal Shot, which aims to cut geothermal energy costs by 90% by 2035. Federal agencies such as the Advanced Research Projects Agency are also investing in cutting-edge geothermal technologies, while recent legislation has improved tax incentives and streamlined regulatory pathways to encourage development. Internationally, the Global Geothermal Alliance, led by the International Renewable Energy Agency, is coordinating efforts among its member nations to dramatically scale geothermal capacity and heating applications by 2030. Countries including Indonesia, Kenya, Iceland, and Turkey are making notable progress, supported by targeted policies, financial incentives, and international partnerships. In regions like Asia, geothermal is increasingly being integrated into urban infrastructure, such as district heating systems, helping reduce reliance on fossil fuels and improve air quality. These collective efforts mark a global shift toward unlocking the technology's full potential across electricity generation, heating, cooling, and industrial applications.

The global geothermal energy landscape is being reshaped by a diverse group of companies, each advancing distinct technologies to unlock Earth's heat for clean power generation.

Leading the charge is Fervo Energy, which applies horizontal drilling and fiber-optic sensing, a technology widely used in the oil and gas sector, to develop Enhanced Geothermal Systems. Fervo is attracting major funding and recently secured $255 million from prominent investors such as Breakthrough Energy Ventures and CPP Investments, and its Cape Station project in Utah has secured over $206 million and signed power agreements with Shell Energy and Southern California Edison, signaling strong commercial traction.

Building on a different approach, Eavor Technologies from Canada is pioneering closed-loop geothermal systems that circulate fluid through a sealed underground circuit, eliminating the need for natural reservoirs. Its projects in Germany and New Mexico have attracted over $175 million in funding from the EU Innovation Fund and the European Investment Bank, highlighting international support for scalable geothermal innovation.

GreenFire Energy is tackling the challenge of underutilized infrastructure by retrofitting idle oil and gas wells with its GreenLoop technology, offering a cost-effective and low-risk path to deployment.

In the realm of ultra-deep drilling, Quaise Energy is developing millimeter-wave technology to reach superhot rock formations up to 20 kilometers below the surface, potentially unlocking gigawatt-scale geothermal capacity. Together, these companies are driving a new wave of geothermal innovation, expanding its geographic reach and positioning it as a key pillar in the global clean energy transition.

Exhibit 43
Nuclear Industry
Leading Companies in the Geothermal Market

Company	Location	Funding Raised	Technological & Market Approach	Strategic Partners
Fervo Energy	Houston, TX	$655M+	Revolutionizing geothermal power through its advanced Enhanced Geothermal Systems (EGS) technology, which leverages horizontal drilling and fiber-optic sensing	Shell Energy, Southern California Edison, Clean Power Alliance
Eavor Technologies	Calgary, AB, Canada	$278M+	The Eavor-Loop system is a closed-loop, conduction-only geothermal technology that delivers baseload and dispatchable power without the need for fracking or water consumption	EU Innovation Fund, JBIC, ING Bank, Mizuho Bank
Dandelion Energy	Mount Kisco, NY	$175M+	Spun out of Google X's Moonshot Factory and its core technology centers on the Dandelion Geo, a ground source heat pump that uses the stable temperature of the Earth to provide heating and cooling	Breakthrough Energy Ventures, Collaborative Fund, LenX, NGP, NEA, Building Ventures, Catchlight Ventures, and GroundUp
Quaise Energy	Cambridge, MA	$95M+	Quaise Energy's approach uses a gyrotron-powered platform to vaporize rock, enabling ultra-deep drilling without complex downhole equipment	Mitsubishi Corporation, Standard Investments, Prelude Ventures
Sage Geosystems	Houston, TX	$56M+	Pioneering pressure geothermal that harnesses both heat and pressure from hot dry rock to enable power generation, energy storage, and direct heating	Meta, Ormat Technologies, GEOLOG Group, Ignis H2 Energy
AltaRock Energy	Seattle, WA	$40M+	Its core innovation lies in hydroshearing that improves the performance of existing geothermal wells by enhancing subsurface permeability, enabling more efficient heat extraction	Google, Advanced Technology Ventures, Vulcan Capital
GreenFire Energy	Walnut Creek, CA	$21M+	The GreenLoop closed-loop system is designed to retrofit underperforming wells and develop new geothermal fields using a technology-agnostic approach tailored to specific geological conditions	Baker Hughes, Helmerich & Payne, Vallourec

Sources: Company reports and William Blair Equity Research

The prices (as of October 10) of the common stock of other public companies mentioned in this report follow:

Antero Resources (Not Covered)	$31.60
Baker Hughes (Not Covered)	$45.04
BWX Technologies (Outperform)	$190.08
Centrus Energy (Outperform)	$363.71
Comstock Resources (Not Covered)	$18.42
Energy Transfer (Not Covered)	$16.29
Enterprise Products Partners (Not Covered)	$30.79
EQT Corporation (Outperform)	$53.12
Expand Energy (Outperform)	$101.76
GE Vernova (Outperform)	$604.56
Gulfport Energy (Outperform)	$175.92
Kinder Morgan (Not Covered)	$27.10
Mitsubishi Heavy Industries (Not Covered)	$26.48
MPLX LP (Not Covered)	$47.80
Oklo (Outperform)	$147.16
ONEOK (Not Covered)	$69.09
Range Resources (Not Covered)	$36.36
Siemens Energy (Not Covered)	$140.07
Targa Resources (Not Covered)	$152.41
Tesla (Outperform)	$413.49
Williams Companies (Not Covered)	$62.61

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